Guide **64**

Facility Inspection Manual

July 2002

Alberta Energy and Utilities Board

Facility Inspection Manual

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ALBERTA ENERGY AND UTILITIES BOARD
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640 – 5 Avenue SW
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T2P 3G4

Telephone: (403) 297-8311
Fax: (403) 297-7040

Web site: <www.eub.gov.ab.ca>

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1 Overview

1.1 Purpose of the Guide

Guide 64:Facility Inspection Manual is designed to ensure that oil and gas production and processing facilities, injection and disposal facilities, and custom treating plants are inspected by EUB Field Centre staff in a consistent manner throughout Alberta. The manual and check sheet are also intended to inform industry personnel about what is required to achieve a satisfactory EUB inspection.

The guide is primarily addressed to Field Centre inspectors. It is also intended for use by industry as a guide to what they can expect during a facility inspection.

The guide must be used with discretion for inspections of heavy oil facilities, as many policies and regulations may not apply. Further information is available in *Industry Recommended Practices for Heavy Oil and Oil Sands Operations* (IRP 3.3 – production equipment and procedures, 3.4 – measurement and accounting) and *ID 91-3: Heavy Oil/Oil Sands Operations*.

1.2 What's New in This Guide

This updated version of *Guide 64* includes recent changes to *Guide 60: Upstream Petroleum Industry Flaring Guide* requirements and *Guide 55: Storage Requirements for the Upstream Petroleum Industry*, as described in *Guide* 55, Section 1.4.3. This updated version also includes some of the Public Safety and Sour Gas (PS&SG) committee recommendations, such as emergency response planning implementation and maintenance.

A description of the new Lease Inspection System (LIS) is included in Appendix 4, detailing the lease inspection form and the minor/major/serious unsatisfactory levels for each inspection item.

In addition, details of the EUB's off-lease H_2S odour management handling process are in the new Appendix 12.

1.3 What This Guide Contains

This guide describes the role of the EUB Field Centre inspectors and includes the EUB check sheet that field staff inspectors complete for each site inspected, accompanied by a step-by-step description of how to complete each part of the form.

There are 15 appendices supplementing information within the guide, including the References and Contacts Cited (Appendix 15).

The purpose of facility inspections is to achieve compliance with EUB regulations and ensure safe and efficient practices at all production facilities.

1.4 The EUB Inspector's Conduct

EUB Field Centre inspectors represent the EUB and must display a positive attitude and fairness to all operators.

Inspectors must offer the facility operator the opportunity to be present prior to a hands-on or active inspection that includes gas meter checking, orifice plate checking, or any activity that may involve opening and closing valves.

Inspectors may, at their discretion, notify company personnel prior to conducting a visual or passive inspection. (See Appendix 3 for more on notification of operators.)

Inspectors should comply whenever possible with company policies that require company notification prior to inspection or lease entry or if the inspection involves the use of specific safety equipment.

Inspectors should have a copy of this inspection manual on site when conducting an inspection, as well as copies of pertinent EUB documents for reference, such as *Guides 55, 58,* and *60*.

Inspectors must always use a cooperative approach as the first method attempted to achieve company compliance with EUB regulations. Where practical, they should have a brief discussion with the company's senior personnel on site after the inspection. This opportunity should be used to establish contacts, exchange information, discuss deficiencies, enforcement, and follow-up, and enhance relations.

1.5 Safety

Inspectors must refer to EUB *Internal Guide 8: Safety Manual* prior to inspection of any facility and be sure to follow the requirements.

They must point out any unsafe operating conditions and practices to the operator. If necessary, they must also advise Alberta Human Resources and Employment, Workplace Health and Safety (formerly OH&S) and/or Alberta Municipal Affairs (formerly Electrical Protection).

1.6 Industry Compliance

The EUB believes that compliance in meeting or exceeding regulations and standards is the responsibility of the energy industry. The EUB expects all industry participants to understand its requirements and have an infrastructure in place to ensure compliance. However, the EUB also recognizes that on occasion enforcement of regulations will be required to ensure compliance.

The EUB has implemented a four-level enforcement policy to address the business issue of noncompliance with provincial requirements. The EUB Field Surveillance Enforcement Process and Ladder (Appendix 2) spells out the enforcement consequences when operators fail to meet requirements and/or regulations. These consequences only escalate to a higher severity when the operator fails to address EUB requirements and requests.

The criteria for determining the level of each infraction are given in Appendix 1: Possible Unsatisfactory Items. EUB Field Centre inspectors follow these criteria when completing the Facility Check Sheet and determining the resulting enforcement action.

2 Inspection Guide and Check Sheet

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Facility Check Sheet

FACILITY NAME ☐

LOCATION ☐

OIL SATELLITE CODE ☐

FACILITY CODE ☐

INSPECTION DATE ☐

TYPE OF FACILITY

☐ Sweet
☐ Sour

☐ Single Oil Battery
☐ Multi Oil Battery
☐ Oil Satellite

☐ Gas Battery/Gas Gathering System
☐ Gas Processing Plant

A. TYPE OF INSPECTION

☐ Initial
☐ Follow up

☐ Surveillance
☐ Audit
☐ Other (Identify) ____________________

B. OPERATION AT TIME OF INSPECTION

☐ Producing
☐ Shut-In
☐ Other (Identify) ____________________

C. INSPECTION RESULTS (Code: Satisfactory "X", Minor "U", Major "M", Serious "S")

MEASUREMENT

1 ☐ Gas
2 ☐ Hydrocarbon Liquids
3 ☐ Water
4 ☐ Other Products

EQUIPMENT

5 ☐ Spacing
6 ☐ Flare System
7 ☐ Drain System
8 ☐ Signage/Security
9 ☐ Pop Tank
10 ☐ Emergency Shutdowns
11 ☐ Compressor Installation
12 ☐ Storage Requirements
13 ☐ Vapour Recovery

ENVIRONMENT

14 ☐ Odour Emissions
15 ☐ Smoke Emissions
16 ☐ Noise Emissions
17 ☐ Waste Management
18 ☐ Housekeeping
19 ☐ Spills
20 ☐ Pits
21 ☐ Surface Runoff Control

OTHER

22 ☐ Compliance with Other EUB Requirements
23 ☐ Emergency Response Plans

ENFORCEMENT (Code: Yes "Y", No "N")

24 ☐ Remedial Action Required by Operator
25 ☐ Letter to Operator Required
26 ☐ Facility Suspended
27 ☐ Records Review of Operator Compliance

ENFORCEMENT ACTION:

Satisfactory Inspection (no action required) ☐

Unsatisfactory Inspection (see reverse) ☐

Non-compliance Level: ____________________

Consequences for non-compliance: ____________________

D.

REMARKS AND COMMENTS: Ensure the following necessary work is completed, and confirmed by the Deadline Date. Contact or fax a copy of this inspection with your comments to the local EUB Field Centre. Be sure to include your name and phone number. Check all your other facilities in the area for the same deficiency.

____

____

____

____

____

____

____

____

Operator's Signature: ____________________

Phone Number: ____________________

Inspector Name: ____________________

Deadline Date: ____________________

Phone Number: ____________________

Fax Number: ____________________

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OPERATORS must ensure that the necessary work detailed under Comments (D) on reverse is completed and confirmed by the deadline date. Contact the local EUB Field Centre or fax a copy of this inspection with your comments to the Field Centre. Be sure to include your name and phone number. Check all of your other facilities in the area for the same deficiencies.

ENFORCEMENT ACTIONS REQUIRED

Minor Level 1

- Local company representative instructed to take corrective action.
- Company must confirm corrective action (**verbally or in writing**) to EUB field centre.
- Maximum time to take corrective action is 30 days.

Minor Level 2

- Local company representative instructed to take corrective action.
- Senior company representative with provincial authority must provide in writing to EUB field centre an explanation of why EUB directive not followed and an acceptable action plan for following EUB directives in the future.
- Maximum time to take corrective action is 15 days.

Minor Level 3

- Full or partial suspension of operations.
- Local company representative instructed to take corrective action.
- Senior company representative with provincial authority must provide in writing to EUB field centre an explanation of why EUB directive not followed and an acceptable action plan for following EUB directives in the future.
- Suspension remains in effect until noncompliance is remedied, a documented meeting/discussion is held with senior company representative with provincial authority, and the EUB removes suspension **in writing**.
- Noncompliance added to Corporate Data Information System.

Minor Level 4

- Immediate suspension (full or partial).
- Suspension remains in effect until documented meeting with senior company representative with provincial authority (VP/Pres).
- Senior company representative with provincial authority confirms compliance at this and all similar facilities in this inspection category.
- Senior company representative with provincial authority must provide a written acceptable action plan, including examination of cause and future prevention plans at this and all similar facilities.
- EUB Corporate Compliance may issue closure order, miscellaneous order, and/or refer status for future applications.

Major Level 2

- Temporary suspension, when safe to do so, may occur (full or partial) to correct deficiency or alleviate impact or potential impact.
- Local company representative instructed to take corrective action.
- Senior company representative with provincial authority must provide in writing to EUB field centre an explanation why EUB directive not followed and an acceptable action plan for following EUB directives in the future.
- Company has 30 days to correct operations in same inspection category on a provincial basis.

Major Level 3

- Same as Minor Level 3.
- Company has 15 days to correct operations in same inspection category on a provincial basis.

Major Level 4

- Same as Minor Level 4.

Serious Level 3

- Full or partial suspension of operations when safe to do so.
- Company instructed to take corrective action.
- Company must explain why event occurred, provide written acceptable action plan, and ensure that issue/event does not reoccur.
- Company must confirm that this and all similar facilities are in compliance.
- Operations remain suspended until noncompliance remedied, EUB accepts action plan, and written approval is received from EUB to resume operations.
- Noncompliance added to Corporate Data Information System.

Serious Level 4

- Same as Major Level 4.

Note: **The above listed enforcement action items are summarized from the EUB Field Surveillance Enforcement Ladder in *Informational Letter (IL) 99-4*. Please refer to this IL or contact the local EUB field centre for further details. The EUB reserves the right to escalate noncompliance issue(s) to any level should conditions warrant.**

2 Inspection and Check Sheet Completion

2.1 When to Use the Check Sheet

The EUB inspector must complete a Facility Check Sheet when conducting a physical inspection of a production facility. Not all items on the check sheet are required to be checked for every inspection. Do not check a box for any item not inspected. Ensure that the inspection is entered on the Production Surveillance System (PSS) database. The check sheet is to be used as a written record of every inspection item examined.

The inspector from the EUB Field Centre must also complete a check sheet if a facility is inspected as a result of a complaint or when a facility is inspected by the EUB air-monitoring unit. The results, including any noted problems and deficiencies, are recorded on the check sheet.

With the exception of follow-up inspections, do not complete the Facility Check Sheet unless an actual physical inspection of a production facility is conducted.

2.2 How to Complete the Facility Check Sheet

Note that the check sheet is in abbreviated form: each item on the form may require several items to be inspected. Each unsatisfactory item should be noted in the most appropriate place, rather than in two or more places.

Leave a copy of the inspection form with the operator or fax a copy to a company representative after completion of each inspection. If the facility is tied in or discontinued and the facility code rescinded, a copy of the Facility Check Sheet should be faxed to the company for its internal records.

Facility Identification

Facility Name

Enter the complete name of the facility, as recorded in PSS.

Location

Enter the facility LSD, section, township, range, and meridian, using the Dominion Land Survey System described in *Guide 59*, Appendix 2.

Oil Satellite Code

Enter the oil satellite code.

Facility Code

Enter the facility code or battery code from PSS.

Inspection Date

Enter the date of the field inspection.

Type of Facility

Check the appropriate box. Ensure that the H_2S category (1-sweet, 2-sour) and battery configuration in PSS are correct.

All facilities with greater than 0.01 mol/kmol (10 ppm) H_2S are sour (see *Guide 56*). Facilities with less than 0.01 mol/kmol (10 ppm) H_2S may also be designated as sour by the Field Centre because of sensitivity. All other facilities are considered sweet.

A Type of Inspection

Check one of the following	**Initial** — an inspection not considered a follow-up. **Follow-up** — an inspection performed due to an unsatisfactory initial inspection. All follow-ups regarding minor unsatisfactory items are to be done by phone whenever possible. Serious and major unsatisfactory items must be followed up on with a physical inspection. Follow-up inspections for major/serious unsatisfactory inspections at **sour facilities** must be conducted within 30 days. An additional initial inspection must then be completed at these same **sour facilities** by March 31, 2003. A follow-up (reinspection) inspection is not considered a satisfactory inspection to get off of the enforcement ladder.
Check one of the following	**Surveillance** — a routine field inspection. This may include OSI and baseline inspections. **Audit** — when one of the following is done: • A complete audit of the operator's records is conducted and each number appearing on the "S" statements is examined for accuracy and is justified. • A detailed operational audit is completed on gas processing facilities. • An application audit is conducted upon referral from the EUB Facilities Applications Group. **Other** — any other type of inspection (identify), including complaint-driven inspections, incident investigations, EUB air-monitoring unit inspections, and inspections of suspended facilities.

B Operation at Time of Inspection

Check one of the following	**Producing** — facility is operating in a normal manner. **Shut-in** — facility is not operating. **Other** — identify if the facility is tied in to other facility or discontinued (equipment removed).

C Inspection Results

All items inspected, except those in the Enforcement category, must be marked "X" for satisfactory, "U" for minor unsatisfactory, "M" for major unsatisfactory, or "S" for serious unsatisfactory.

Items in the Enforcement category must be marked "Y" for yes or "N" for no. See Appendix 1 for possible unsatisfactory items.

Reported Production Data Differ from Actual Volumes

EUB inspectors must notify the investigations coordinator in the Production Operations Group when it appears that reported production data do not reflect actual volumes. This issue may arise when

- a complaint alleging the situation is received, or
- staff discover the situation during an inspection.

The investigation coordinator will take the lead role and decide upon the actions to be taken. Do not contact the operator/licensee until the investigation is completed. Staff must treat all situations of this nature as confidential and restrict access to information to the investigation coordinator and the appropriate team leader, unless advised otherwise.

1 Gas

1.1 General

a) Meter run and measurement device must be installed and operated in accordance with Sections 14.030 to 14.080 inclusive of the Oil and Gas Conservation (OGC) Regulations and in compliance with *AGA Report No. 3* or *7* and *ID 90-2*.

b) Measurement devices must be installed and operated in accordance with the manufacturer-recommended specifications.

c) Emergency flaring and gas well blowdowns must comply with requirements (*Guide 60*, Section 10) for determination of flared/vented volumes.

d) The volume of gas vapours flashed from condensate or oil storage tanks is determined in accordance with the requirements (*Guide 60*, Section 10) for determining flared/vented volumes and reported as part of the total facility gas production.

e) Meter calibrations must be conducted in accordance with *ID 90-2*.

f) For automated measurement systems, see *Guide 46*, Appendix D-5.

1.2 Well Site

a) Well gas production must be determined and reported as stipulated in *Guide 7*.

b) Test gas for oil wells may be estimated based on gas-oil ratio tests as identified in *IL 91-9* for conventional oil wells and Section 4.3 of *ID 91-3* for crude bitumen or heavy oil wells.

c) Gas production for wells in a southeastern Alberta proration system must be determined and reported as per *IL 93-10*.

d) Effluent measurement test taps for connecting the portable test separator must be installed downstream of the wellhead effluent meter to ensure that the normal flow rate is not disturbed. Effluent meter correction factors for gas wells must be determined on a semi-annual basis (*Guide 4*).

1.3 Plants

a) Gas processing plants require adequate inlet gas and condensate measurement in order to achieve an accurate balance from the field to the plant. Well measurement may be used as plant inlet measurement for facilities with EUB approval.

b) A continuous stack emissions monitor (CSEM) is a requirement for sour gas plants recovering sulphur and may also be required by some acid gas flaring plants. The inspector should ask to see the Alberta Environment (AENV) approval, which stipulates the requirements. The inspector should look for data providing the stack top temperature, the maximum hourly emission rate, and the maximum daily emission rate and compare the findings with the AENV approval. This information should be available at the plant, along with the date of the last stack survey.

1.4 Fuel

a) Fuel gas taps should be located downstream of the gas production meters to ensure that total gas production is measured. If the fuel tap is located upstream of the gas production meter, fuel gas must be measured or estimated in accordance with the following:

- Fuel gas measurement is required if fuel gas volumes exceed 500 m^3/day.
- If fuel gas volumes do not exceed 500 m^3/day, volumes may be determined using an engineering estimate based on manufacturer specifications or a previous measurement of fuel consumption rates.

b) Rotary displacement meters used to measure transporter or distributor sales specification fuel gas are exempt from the calibration requirements of *ID 90-2*. A calibration frequency of seven years is acceptable, providing the meter is calibrated against a known gas volume through a certified proving device. The meter must be calibrated or proved following any repairs.

c) Dilution gas added to an acid gas stream to ensure complete combustion during flaring is considered fuel gas. Dilution gas must be measured as stipulated in the AENV approval and in *Guide 60*.

1.5 Flare/Vent

a) Flare gas volumes, including emergency flaring and gas well blowdowns, may be measured continuously or estimated using an appropriate engineering estimate. The accuracy of flare measurement is questionable due to the wide range of flaring rates and gas densities. Use discretion when determining the accuracy of this measurement.

b) Stock tank vapours may be estimated in accordance with *Guide 60.*

c) See *ID 99-6* and *Guide 60* for further information regarding estimating and measurement of flared and vented gas.

d) To meet the measurement accuracy guidelines as defined in *ID 94-1*, the following flare or vent gas sources will require measurement in accordance with *Guide 60*:

- continuous or routine flare sources in conventional oil and gas production or processing facilities where annual average flare volumes exceed 500 m^3/d
- solution gas flared from heavy oil or crude bitumen production facilities within designated oil sands area where annual flared or vented volumes exceed 2000 m^3/d

1.6 Acid Gas

a) The acid gas stream is saturated with water vapour. This vapour represents a significant portion of the total gas measured. The amount of water vapour varies significantly with temperature; therefore it is necessary that the meter be equipped with a continuous temperature recorder.

b) Continuous or emergency acid gas flared from gas sweetening systems must be measured in accordance with *Guide 60.*

1.7 Data Recording

a) The OGC Regulations, Section 14.070(3), states: “The licensee of an oil well at which gas is produced shall use for the metering of gas production a 24-hour chart drive unless the Board, upon application and upon being satisfied that gas production can be accurately determined, permits the use of a slower clock drive.”

Seven-day chart approvals are typically given for gas measurement at single well batteries and for group and fuel measurement at proration batteries. They are not typically given for well test measurement unless the test is for a seven-day duration. Seven-day charts are not acceptable for Class I and Class II wells. However, *ID 94-1* allows operators to utilize seven-day chart drives for extended duration tests (multiday tests) for low rate and stripper wells (Class III and Class IV), with only one extended-day well test per chart.

Where a seven-day chart is in use, assess the overall measurement system. If the quality of the system is unsatisfactory (including the chart), the inspector should require the operator to use a 24-hour chart drive.

b) The OGC Regulations, Section 14.070(2), states: "The licensee of a gas well shall, unless otherwise directed by the Board, use for the measurement of gas production either a circular chart drive, not slower than seven days per cycle, or a suitable strip chart."

Application for chart drives slower than seven days must be submitted to the Operations Group in Calgary. Frequently, applications are received for use of charts slower than a 7-day cycle, typically 8-day, 16-day or 31-day charts.

2 Hydrocarbon Liquids (Oil, Crude Bitumen, Condensate, and NGL)

2.1 General

a) Any system used to measure hydrocarbon liquids must be able to provide readings to two decimal places (e.g., 0.01 m^3).

b) Hydrocarbon liquids may be measured by tank gauge. This includes test production, group production, or measurement of trucked fluids. (See Appendix 5.)

c) Measurement of hydrocarbon liquids may be done through a meter.

The OGC Regulations, Sections 14.100 to 14.120 inclusive and Section 14.180, govern oil measurement.

The OGC Regulations, Sections 14.090 and 14.180, govern condensate measurement.

The flow rate and pressure drop through the meter must be within manufacturer specifications (see *Guide 46*).

Liquid orifice meters must be installed in accordance with the American Gas Association *Report No. 3* and the *Orifice Meter Constants Handbook E-2*.

New types of measurement devices coming on the market must be proved in the same manner and at the same frequency as conventional meters.

Crude oil delivery points have stringent measurement requirements. See *IL 92-8* and *ID 94-1*.

d) Meters must be calibrated in accordance with the OGC Regulations, Sections 14.010 to 14.200 inclusive.

Condensate meters with a throughput volume of 2.0 m^3/d or greater must be proved in line to flow conditions. Condensate meters with a throughput of 2.0 m^3/d or less may be bench calibrated. Ensure that the dump valves are inspected for leakage in conjunction with the bench calibration of the meters. (See Appendix 6.)

Where production rates are low, oil meters may be shop calibrated. (See Appendix 6.)

Test oil meters for heavy oil or crude bitumen wells may be calibrated in accordance with requirements set out in *ID 91-3*, Section 4.4.

2.2 Other

a) Test separator and group header pressures should be within 200 kPa of each other.

b) Oil wells within a proration battery must be tested in accordance with *ID 94-1*.

c) Crude bitumen or heavy oil wells within a proration system must be tested in accordance with *ID 91-3*, Section 4.2.

d) Volume determinations for LPG/NGL, storage vessels must be supported by strapping tables provided by the manufacturer or determined by a qualified technician.

3 Water

3.1 General

Meter run and measurement device must be installed and operated in accordance with OGC Regulations, Sections 14.140, 14.160, and 14.180. Measurement devices must be installed and operated in accordance with the manufacturer-recommended specifications (pressure drop and flow rate within recommended range of the meter).

3.2 Gas Wells

Water production at gas wells must be determined and reported as per *Guide 4*. Water cuts may be allowed for gas wells under special circumstances (e.g., wells producing an emulsion, accounting purposes).

3.3 Oil Wells

a) Where the test water/total test liquid ratio exceeds 0.1 m^3/m^3, test water must be determined by a test treater or, where none is available, a proportional sampler or net oil analyzer (OGC Regulations, Section 14.150).

If test water is measured off a treater, it must be done as per the OGC Regulations, Sections 14.140 to 14.180.

b) Where the test water/total test liquid ratio is less than 0.1 m^3/m^3, test water may be determined using two well-spaced samples or as above (OGC Regulations, Section 14.150(2)).

c) By witnessing water-cut work done by the operator using a centrifuge, determine if water-cut methods used are in accordance with API standards. See *Guide 46* for fluid sampling and water-cut procedures.

d) Where water cut exceeds 10 per cent or samples contain free water, operators should use a graduated cylinder and heat bath or a comparable process.

4 Other Products

4.1 Sulphur

Sulphur storage tanks must be properly strapped to allow for the determination of inventories.

Equipment

5 Spacing

a) Equipment spacing must be in accordance with the OGC Regulations, Sections 8.030(2), 8.080(2)(3), and 8.090, and *ID 91-3* and *Guide 60*. (See diagram, Appendix 7.)

b) Pressure relief valves and burst plates are considered a source of ignitable vapours. If they are located in the same process building as flame type equipment, they must be vented above roof level (OGC Regulations, Section 8.090(6)).

c) Pressurized separation/storage vessels (railway cars) must not be placed within 25 m of a flare or well.

d) Determine if tank heaters in oil tanks meet criteria. (See Appendix 8.)

e) Gas compressors are not considered flame type equipment. The end of an exhaust pipe from an internal combustion engine must not be located within 6 m of the vertical centre line of the well and must be directed away from the well (OGC Regulations, Section 8.090(9)(b)).

6 Flare System

a) Any significant volume of gas directed to a flare stack or incinerator must be burned in accordance with the OGC Regulations, Section 8.080.

b) All sour gas must be flared in accordance with the OGC Regulations, Sections 7.040 to 7.070 inclusive, and *Guide 60*.

c) Flare systems must be designed and operated in accordance with the Flare Performance Requirements outlined in *ID 99-6* and *Guide 60* (also see Appendix 9). The requirements apply to all flare systems installed at well testing locations, well sites, oil and gas batteries, and gas processing facilities.

Compliance deadlines are
- December 31, 2002, for all existing solution gas flares
- December 31, 2004, for flares at other existing permanent facilities

d) *Guide 60* stipulates that sufficient fuel gas be added to this acid gas or sour gas flare such that the heating value of the gas stream is not less than 12 MJ/m^3.

e) A flare knockout drum is not required if the only vessels connected to the flare system are separators equipped with a high-level shutdown (HLSD) and the flared volume will not exceed $5\ 10^3$ m^3/d.

7 Drain System

a) Dehydrator still column vent lines may vent to atmosphere. However, if hydrocarbon or chemical carryover is present, suitable tankage is required.

b) Vessel drains, lube oil drains, and floor drains must be tied into suitable tankage.

8 Signage/Security

a) Identification and warning signs must conform to the OGC Regulations, Section 6.020.

b) A well or facility must have at least one warning sign posted — the H_2S symbol for wells or facilities with more than 0.01 mol/kmol (10 ppm) H_2S or a flammable sign for sweet wells or facilities.

c) Facilities with H_2S excess of 10 mol/kmol (1 per cent) must be fenced in accordance with the OGC Regulations, Section 8.170.

9 Pop Tank

a) All pressure relief valves, rupture disks, or burst plates installed on a separator, treater, or other pressure vessel at an oil facility must be secured to an open pop tank via self-draining lines (OGC Regulations, Section 8.031).

b) The relief line must terminate in the upper third of the tank.

c) The size of the pop tank must be sufficient to hold the unattended production of the facility. The pop tank may be sized smaller or replaced if a high-pressure shutdown device is installed on the vessel. In the case of oil facilities with large production volumes, pop tanks may be sized to 80 m^3, providing additional storage capacity is made up by a secondary containment device, as per *Guide 55*. Where economics are marginal, the use of a production tank as a pop tank may be permitted with EUB Field Centre approval.

d) Where a high-pressure shutdown device is in use, an isolation valve must be installed between the pressure sensor and the vessel to allow the sensor to be tested. The pressure sensor should be tested every three months.

e) The pressure-sensing device must be set to operate at a pressure below the relieving pressure of the pop valve and burst plate.

f) A pressure vessel at a sour facility must be equipped with a pressure and liquid level control that a causes valve installed on the inlet to close and isolate the vessel from the flow stream (OGC Regulations, Section 7.060(3.1)).

10 Emergency Shutdowns

a) Surface shutoff valves are required by the OGC Regulations, Section 7.060(8), for all wells with H_2S concentration greater than 10 mol/kmol (1 per cent) that exert a pressure of greater than 1400 kPa on the flow line. The valves must be set to close on low pressure in the event of uncontrolled flow of oil or gas and on high pressure if the well is capable of building up a pressure that exceeds maximum operating pressure (MOP) of the flow line.

b) Subsurface shutoff valves are required by the OGC Regulations, Section 7.050(7), for wells with H_2S concentration in excess of 50 mol/kmol (5 per cent) that are capable of flowing 140 x 10^3 m^3/d and are within 800 m of an occupied dwelling or within 8 km of a city, town, or village.

c) Surface and subsurface shutoff valves must be installed and operated in accordance with API specifications.

d) A valve that closes automatically must be installed at any well or battery located within 100 m of a normal high-water mark of a body of water or permanent stream (OGC Regulations, Section 8.060(a)).

11 Compressor Installation

a) All permanent compressor installations greater than 75 kW must have EUB approval (see *IL 88-5*, *ID 96-2*, and *Guide 56*).

b) Temporary compressors operating more than 21 days at one location require an approval from the EUB. Temporary compressors operating fewer than 21 days at one location do not require an approval, providing that the operator notifies the surrounding residents and there are no objections. It is not necessary for the operator to notify the EUB of a temporary compressor operating fewer than 21 days at one location.

c) The exhaust stack height for compressor facilities emitting less than 16 kg/h of NO_x must be 1.2 times the peak height of the compressor building. The exhaust stack height must not be less than the building peak height.

d) Compressors larger than 600 kW must utilize low NO_x technology (e.g., catalytic converters, rebuilt engines).

12 Storage Requirements

a) Appropriate material and waste storage must be conducted in accordance with *ID 95-3* and the 1995 and 2001 editions of *Guide 55*. This includes aboveground tanks, underground tanks, containers, storage facilities, bulk pad storage, and inspection monitoring and record keeping requirements for those materials produced, generated, or used by the upstream petroleum industry under EUB jurisdiction.

b) Facilities constructed and operating prior to January 1, 1996, are required to demonstrate that their storage practices, facilities, and containment devices met the requirements of *Guide 55* by October 31, 2001. Facilities constructed between January 1, 1996, and January 1, 2002, must meet the storage requirements in the 1995 edition of *Guide 55*. The following implementation dates for new/revised requirements in the 2001 edition of *Guide 55* must be met:

- Effective January 1, 2002, the frequency for monitoring leak detection systems associated with storage devices shall be monthly.
- Effective January 1, 2002, the use of single-walled underground storage tanks where a synthetic liner or the natural impermeable soil conditions are used as secondary containment will no longer be allowed. Any systems installed between January 1, 1996, and January 1, 2002, must meet the requirements outlined in Appendix 2 of the 2001 edition of *Guide 55*.
- Effective January 1, 2002, the use of concrete-lined earthen excavations with an underlying leakage monitoring system (no secondary containment) and the use of concrete as primary containment for lined earthen excavations or for bulk pads where there is a potential for the stored materials to generate a leachate will no longer be allowed. Any system installed prior to January 1, 2002, must meet the requirements outlined in Appendix 2 of the 2001 edition of *Guide 55*.

- Facilities constructed and operating prior to January 1, 1996, have until October 31, 2004, to meet the secondary containment requirements for small aboveground tanks exceeding the total combined volume of 5 m^3 per site, as presented in Section 5.3 of the 2001 edition of *Guide 55*.

c) Refer to Appendix 10 for a summary of the general requirements for permanent storage facilities (2001 edition of *Guide 55*, Table 2).

d) Pressurized separation/storage vessels (railway car vessels) are exempt from the *Guide 55* storage requirements (no dike or liner required), provided there is no thief hatch or atmospheric overflow on the vessel. The pop valve must be tied into the flare system or an open tank and the line to the flare system must be self-draining.

e) The EUB does not regulate the diking of pressurized LPG vessels. Grading of the area and proximity of the bullet to other atmospheric storage tanks must conform to the *National Standard of Canada CAN/CGA B149.2-OO CODE Propane Installation Guide* (see Appendix 11).

13 Vapour Recovery

a) Vapour recovery is required for facilities with emissions greater than 10 mol/kmol H_2S (1 per cent). As well, vapour recovery may be required for facilities handling any concentration of H_2S if there is a potential for off-lease emissions.

b) All sour tank vapours must be conserved or gathered and burned (OGC Regulations, Section 7.070(3)).

c) Vent lines from storage tanks directed to flare pits or flare stacks must be provided with flame arresters or other equivalent safety devices (OGC Regulations. Section 8.090(7)).

Environment

14 Odour Emissions

a) In accordance with the OGC Act, Part 1(4)(f), the EUB has jurisdiction to control pollution above, at, or below the surface in the drilling of wells and in operations for the production of oil and gas. In this regard, migration of H_2S emissions off lease is considered pollution and may be defined as a major unsatisfactory inspection. See Appendix 12 for further guidance.

b) Air contaminants from a well, battery, or gas processing plant must not exceed Alberta Ambient Air Quality Guidelines in accordance with the OGC Regulations, Sections 7.070(4) and 9.040:

- Hydrogen sulphide (H_2S) in the ambient air shall not exceed an average maximum permissible concentration of
  - 0.003 ppm as a 24-hour concentration
  - 0.010 ppm as a 1-hour concentration

- Sulphur dioxide (SO_2) in the ambient air shall not exceed an average maximum permissible concentration of
  - 0.06 ppm as a 24-hour concentration
  - 0.17 ppm as a 1-hour concentration

c) The OGC Regulations, Sections 9.050(6)(b) and 9.050(6)(c), require the satisfactory control of unburned hydrocarbon vapour and odorous material emissions at gas processing plants.

d) Emissions contained to the lease area should be noted on the facility check sheet even though the inspection is considered satisfactory. However, the operator must also be instructed to take corrective actions to reduce or eliminate minor emission source(s).

15 Smoke Emissions

a) Smoke emissions from a well, battery, or gas plant must be controlled in accordance with the OGC Regulations, Sections 7.040(1) and 9.050(6)(d), except under emergency circumstances due to equipment failure or as otherwise approved by the EUB.

b) Significant or visible smoke emissions that have the potential to cause public concerns must be investigated and the operator requested to conduct remedial actions to reduce or eliminate smoke emissions.

c) Smoke from flare stacks must not exceed 40 per cent opacity averaged over six consecutive minutes, as specified in the Alberta Environmental Protection and Enhancement Act (EPEA) Substance Release Regulations.

16 Noise Emissions

a) Production facilities must meet the requirements of the EUB *Noise Control Directive* as outlined in *ID 99-8* and *Guide 38*.

b) Normally noise levels are not checked during a surveillance inspection. If a facility is inspected as a result of public concerns and a noise monitoring survey is requested, the results of the survey must be recorded on the inspection check sheet.

17 Waste Management

a) Appropriate management of oilfield waste must be conducted in accordance with *ID 96-3* and *Guide 58* as they apply to all oil and gas, oil sands, and oilfield waste management facilities under EUB jurisdiction. Appropriate management, as it pertains to this manual, includes generator and receiver responsibilities, importation, characterization/classification, manifesting and tracking, storage/transfer facilities, and disposal.

b) The oilfield waste generator (i.e., EUB licensee and/or approval holder) is responsible for ensuring that the requirements in *Guide 58* are followed, including

- properly characterizing and classifying their oilfield wastes,
- utilizing appropriate treatment and disposal practices,
- understanding the capabilities and limitations of the method selected for the treatment and/or disposal of their wastes,
- maintaining accurate and complete waste documentation and manifests,
- informing waste carriers and receivers of the properties of their oilfield wastes, and
- ensuring that operational requirements have been satisfied and, if applicable, required approvals are in place for any on-site waste handling, treatment, and disposal method.

18 Housekeeping

a) Production facilities must be maintained in a clean condition (OGC Regulations, Section 8.150(6)).

b) Garbage or loose debris must be stored in a reasonable manner (OGC Regulations, Section 8.150(2)(a)).

c) Oil-stained areas must be cleaned up. If the spill material is removed, it must be disposed of in a manner as outlined in *Guide 58*.

d) All dikes and firewalls must be maintained in good condition and the area must be kept free of grass, weeds, or other extraneous combustible material (OGC Regulations, Section 8.030(1)).

19 Spills

a) The OGC Regulations, Section 8.050(1), requires the operator to take immediate steps to contain and clean up oil and saltwater spills. Contaminated spill materials must be handled and disposed of in accordance with *Guide 58*. Ensure that the operator advises the landowner of any spills off lease.

b) An oil or saltwater spill off lease or any spill in excess of 2 m^3 on lease must be reported immediately to the EUB in accordance with the OGC Regulations, Section 8.050(2).

c) Spills of refined products are the responsibility of AENV. Operators must notify the AENV's Pollution Control Division of any refined product spills.

d) Field inspection staff are expected to use discretion when differentiating between spill and housekeeping deficiencies. However, spillage having the potential to adversely impact the environment must be considered a spill rather than a housekeeping deficiency. The following situations are considered a spill rather than a housekeeping deficiency:

- areas with pooled hydrocarbons or areas heavily caked with hydrocarbons
- extensive staining throughout the lease areas
- cumulative spillage of small volumes of hydrocarbons over a long period of time
- spills outside the lease area

20 Pits

a) The inspector must determine the purpose and need of the pit and identify the source(s) of all lines running into the pit.

b) Flaring to earthen pits is prohibited at all new facilities constructed after July 1, 1996 (*IL 96-4* and *Guide 60*).

c) Flaring at existing facilities (constructed and operating prior to July 1, 1996) to flare pits is acceptable, consistent with *IL 96-4* and *Guide 60*, provided there is no potential for produced fluids to enter the pit. Appropriate flow shutoff and emergency containment devices must be installed, such as high-level/high-pressure shutdown devices, flare knockout drums, and wellhead ESDs.

d) Pits must not be used as storage for crude bitumen, liquid hydrocarbons, process chemicals, or water produced from a well or associated facility (OGC Regulations, Sections 8.010 and 8.040(2)).

e) Shallow gas producers in southeastern Alberta will no longer be allowed to release fluids and solids to a pit, in accordance with *IL 99-5*. Appropriate storage and disposal facilities must be in place by September 30, 2000, for existing wells. New wells drilled after January 1, 2000, must have the appropriate equipment in place immediately.

f) The licensee must construct and safeguard all flare pits and end of flare lines so that no hazard exists to public property or to surrounding forest cover, as outlined in the OGC Regulations, Section 8.080(2).

g) Operators may find it necessary to remove water from a flare pit due to excessive precipitation. Water must be removed and disposed of at an approved disposal site or released to the surrounding watershed, provided the operator meets the criteria outlined in *Guide 58,* Section 11.6(2)(b).

21 Surface Runoff Control

a) A lease dike or other containment system is required for any well or battery within 100 m of a body of water or permanent stream (OGC Regulations, Section 8.060(c)). Some leases may require diking, grading, or levelling to prevent entrapment of water onto the lease area.

b) Disposal of process waste water, sanitary sewage, and surface runoff at EUB/AENV-approved facilities must meet the requirements stipulated in the AENV approval (OGC Regulations, Section 9.050(8)(b)).

c) The criteria stipulated in *Guide 55* and *Guide 58* must be met prior to the release of any surface runoff water to adjacent lands at EUB-approved facilities.

d) Improper use of sterilants and any adverse effects related to their use are the responsibility of AENV. The appropriate AENV regional office must be advised of sterilant-related problems.

Other

22 Compliance with Other EUB Requirements

a) The primary purpose of this inspection item is to ensure compliance with all other EUB requirements not specified elsewhere in this guide. This includes compliance with current EUB regulations, interim directives (IDs), informational letters (ILs), guides, policies, and any approvals relevant to the facility.

b) Ensure that suspended facilities comply with current EUB requirements (*ID 98-2*).

23 Emergency Response Plans

a) Emergency response plans (ERPs) for sour facilities must meet the requirements of *IL 90-17* and *ID 2001-5*. A site-specific ERP is required if a critical sour well is tied into an existing facility and/or there are residents and public use facilities within the emergency planning zone (EPZ).

Note that EPZ calculations are based on a 100 ppm isopleth using a maximum potential release rate and/or release volume.

b) A corporate-level ERP is required for other facilities, as per *ID 91-2*.

c) A minimum of two public contacts (personal visits, phone calls, or letter when resident is not home) must be completed with residents within the EPZ for each facility inspected with an approved ERP. The results of the public contacts must be recorded on the resident contact forms and entered into the database.

d) When conducting a review of an ERP for a sour facility, the ERP check sheet in Appendix 13 must be completed by the inspector and retained on file.

Enforcement

24 Remedial Action Required by Operator

Enter "Y" (yes) if unsatisfactory items are noted that require remedial action. Enter "N" (no) if remedial action is not required and the inspection is considered satisfactory. See Appendix 2 for further details.

25 Letter to Operator Required

Enter "Y" (yes) if a letter to the company is required. Enter "N" (no) if a letter is not required. See Appendix 2 for further details.

26 Facility Suspended

Enter "Y" (yes) if the facility is being partially or fully suspended as a result of noncompliance. Enter "N" (no) if the facility is not suspended. See Appendix 2 for further details.

27 Records Review of Operator Compliance

Enter "Y" (yes) if the records were reviewed for the inspection. Enter "N" (no) if records were not reviewed for the inspection. See Appendix 14 for further details.

Enforcement Action

Enter “X” if the inspection is satisfactory.

Enter the appropriate code if the inspection is unsatisfactory.

Indicate the appropriate noncompliance level and escalating consequence level of future noncompliance.

D Remarks and Comments

Clearly define the necessary work that must be completed by the operator in the Remarks and Comments section.

Operator’s signature

Be sure that the operator of the inspected facility signs the completed inspection sheet.

Phone number

Enter the operator’s phone number, including area code.

Inspector’s name

Enter the inspector’s name, phone number, and fax number, including area codes.

Deadline date

Enter the date by which the necessary work detailed under Remarks and Comments must be completed.

2.3 Submission of Check Sheet

Give the operator a copy of the completed check sheet.

File the completed Facility Check Sheet with Local Field Centre.

Appendix 1 Possible Unsatisfactory Items

The level of each infraction is based on the criteria set out in *IL 99-4* (Appendix 2).

Inspection Results

- **Minor unsatisfactory event/inspection (U)** — a contravention of regulation(s) or requirement(s) that does not result in a direct threat to the public or the environment and does not adversely affect oil and gas operations.
- **Major unsatisfactory event/inspection (M)** — a contravention of regulation(s) or requirement(s) that an operator has failed to address or that has the potential to cause an adverse impact on the public or the environment.
- **Serious unsatisfactory event/inspection (S)** — a total disregard for regulation(s) or requirement(s) that is having or may have a significant impact on the public or the environment.

The EUB may escalate noncompliance issue(s) to any level should conditions warrant.

Compliance and Noncompliance Results

Inspection results are rated "X" – satisfactory, "U" – minor unsatisfactory, "M" – major unsatisfactory, or "S" – serious unsatisfactory. Items below are numbered in accordance with the Facility Check Sheet.

An unsatisfactory measurement inspection item that results in an impact to the stakeholders of more than \$50 000 is considered a major unsatisfactory (M).

1. Gas

A. General

U 1. No gas measurement for oil well and battery/group, production > 500 m^3 gas per day (>2000 m^3 gas per day for heavy oil).

U 2. No group gas measurement when required.

U 3. No inlet gas measurement or total inlet gas not measured at a gas plant.

U 4. Gas production determined by the difference of two meters.

U 5. Gas recycle line tied in upstream of inlet gas measurement.

U 6. Effluent measurement test taps installed upstream of the well effluent meter.

U 7. New measurement technology or design does not meet Schedule 9 accuracy guidelines.

U 8. Meter not installed or operated in accordance with the manufacturer-recommended specifications.

U 9. Meter not operating or not properly in service.

U 10. Meter subject to excessive pulsation or surging.

U 11. Valve on meter-run bypass line open.

U 12. Meter not calibrated since installation, not calibrated following repairs, or calibration expired.

U 13. No calibration card or sheet attached to recorder.

U 14. Improper calibration procedures.

U 15. Recorder not housed, protected from weather, or properly mounted.

U 16. Meter run does not meet AGA 3 specifications (insufficient upstream/downstream pipe lengths, etc.).

U 17. Meter run not stamped.

U 18. Orifice plate changer inoperable (leaks, seized, etc.).

U 19. Fluids in orifice plate changer.

U 20. Orifice plate unsatisfactory (plate size not stamped, backwards, dished, nicked, waxed up, improperly seated, etc.).

U 21. Orifice plate seals inadequate or leaking.

U 22. Orifice plate not checked on every calibration. (Meters equipped with flange connections or slow-change orifice plate holders may be inspected during shutdowns.)

U 23. Improper storage of orifice plates.

U 24. Sensing lines between orifice changer and recording device contain fluid traps.

U 25. Leaks in sensing lines/valve manifold.

U 26. Improperly sized orifice plate (differential pen not operating in accurate range of chart scale). Recommend pen operate in upper two-thirds of the chart.

U 27. Improper static or temperature element installed (pens not operating in accurate range of chart).

U 28. Orifice to pipe diameter beta ratio not within or equal to the recommended limits of 0.15-0.70 or as per manufacturer's specifications.

U 29. No thermometer well or no adequate means of determining flowing gas temperature.

U 30. Differential pen not zeroed on regular basis or pen reading below zero.

U 31. Excessive differential pen fluctuations or chart painting.

U 32. No gas measurement on gas well, unless otherwise approved.

U 33. Improper pen arc or pen pressure.

U 34. Pens out of ink or not inking continuously.

U 35. Incorrect or insufficient information recorded on chart.

U 36. Improper chart drive speed/inappropriate use of multiday charts.

U 37. Oil dump valve leaking, allowing unmeasured gas to pass directly to tanks.

U 38. Measurement not as per approval (miscible flood, gas lift, etc.).

U 39. Annual gas-oil ratio (GOR) test not conducted.

B. Fuel gas

U 1. Fuel gas volumes in excess of 500 m^3/day not measured.

U 2. Rotary positive displacement meter not installed or operated in accordance with OGC Regulations, Section 14.080 (specify).

U 3. No accurate method of estimating fuel gas consumption (where applicable).

U 4. No plant fuel gas measurement or total plant fuel gas not measured.

C. Flare gas/acid gas/vented gas

U 1. No flare measurement (when required), or total flare measurement inadequate.

M 2. No acid gas measurement, or total acid gas not measured.

U 3. Acid gas meter not equipped with a continuous temperature recorder.

U 4. No accurate method of estimating flare or vented gas volumes.

M 5. Dilution gas volumes not measured.

M 6. No CSEM where required.

U 7. Flare/vent documentation not completed on daily basis.

U 8. Flare/vented gas not reported.

2. Hydrocarbon Liquids (Oil, Crude Bitumen, Condensate, and NGL)

A. General

U 1. Meter not calibrated/proved since installation or repair.

U 2. Meter calibration/proof expired.

U 3. Meter bench calibrated where volumes > 2.0 m^3 (condensate only).

U 4. System not as follows: separator-meter-snap acting dump valve-calibration prover taps.

U 5. Flow rate through meter not within manufacturer specifications.

U 6. Meter or net oil analyzer not set up within manufacturer specifications.

U 7. Dump valve leaking (evidenced by meter creeping or separator level dropping while dump is closed).

U 8. New measurement technology or design does not meet Schedule 9 accuracy guidelines.

U 9. Tank gauging inaccurate.

B. Oil/crude bitumen

U 1. No test oil measurement (test tank or meter).

U 2. Test procedures not satisfactory (not flushing common flow lines, test not of sufficient duration, etc.).

U 3. Tests are not representative because of test separator and group header pressures at satellite differing by more than

200 kPa, or test and group separator are on site and differ by more than 200 kPa.

U 4. No group oil measurement (company pipeline).

U 5. Trucked-in oil estimated strictly by truck size (no tank or meter measurement).

U 6. Trucked-in oil emulsion basic sediment and water (BS&W) determined in an inaccurate manner.

C. Condensate/NGL

U 1. Inadequate well condensate measurement or estimate.

U 2. Improper calibration procedures (condensate meter bench calibrated or calibrated to stock tank conditions, etc.).

U 3. Dump valve not snap-acting type (throttling valve may be acceptable, providing the valve will function within the operating range of the meter). Note that where an orifice meter is used to measure condensate, the majority of unsatisfactory inspection items listed under gas measurement are applicable.

U 4. No plant inlet condensate measurement, or total plant inlet condensate not properly determined.

U 5. Condensate recycle line tied in upstream of inlet condensate measurement.

3. Water

U 1. No well water measurement or water-gas ratio (WGR) tests.

U 2. Meter not installed and operated in accordance with the manufacturer-recommended specifications.

U 3. Meter not installed in accordance with OGC Regulations, Section 14.180.

U 4. Water meter not calibrated/proved or not calibrated/proved following repairs, or water meter calibration expired.

U 5. No meter calibration tag.

U 6. No proportional sampler or analyzer where water cut is > 10 per cent or the sampler/analyzer is inoperable.

U 7. Water-cut procedures inaccurate.

U 8. No inlet water measurement where water production is > 50 m^3 per month.

4. Other – Sulphur

U 1. Pit gauging equipment or procedures inadequate.

U 2. Measurement device inadequate.

5. Spacing

U 1. Tanks to surface improvement (other than roads) less than 60 m.

U 2. Fire less than 50 m from a well.

U 3. Fire less than 50 m from a hydrocarbon liquid storage tank.

U 4. Fire less than 50 m from a source of ignitable vapours.

U 5. Hydrocarbon liquid tanks to well less than 50 m.

U 6. Flame-type equipment to well less than 25 m.

U 7. Flame-type equipment to hydrocarbon tank less than 25 m.

U 8. Flame-type equipment to source of ignitable vapour less than 25 m.

U 9. Flame-type equipment without workable flame arrester less than 25 m from a process vessel. Check to ensure flame arrester has all bolts, is not saturated with oil, is properly fitted, and has gasket where required.

U 10. Air intake of flues for a burner inside a building containing a pressure vessel.

U 11. Flare pit or stack less than 25 m from oil or gas processing equipment.

U 12. Flare pit or stack less than 100 m from surface improvement except roadway.

U 13. Internal combustion engine exhaust within 25 m of a well, process vessel, storage tank, or source of ignitable vapours has flame emergence.

U 14. End of exhaust pipe from internal combustion engine located within 6 m of the vertical centre line of the well/is not directed away from the well.

U 15. Use of a tank heater does not meet requirements in Appendix 8.

U 16. Smoking within 25 m of a well separator, oil storage tank, or other source of ignitable vapours.

M 17. Flare stack less than 100 m from an occupied residence.

6. Flare System

U 1. No knockout drum, or flare separator/knockout drum or flare separator inadequate.

M 2. No flare stack where required.

U 3. Significant volume of gas vented/not burned (> 500 m^3/d).

U 4. Stack height does not conform to requirements.

M 5. Sour pressure relief valves not tied into flare system where required.

M 6. No flame arrester on line from tank to flare stack where required.

U 7. No wind guard on gas sour/acid flare when exit velocity is not sufficient.

M 8. Pilot/ignition device not available/operable (intermittent sour and acid gas flares).

M 9. Insufficient fuel gas to acid gas or sour gas flare.

M 10. No high-level alarm on knockout drum/flare separator where required (*Guide 60*, 7.3.5(7)).

M 11. Operating procedures and/or automatic shutdowns not in place to control major sour/acid gas flaring events.

U 12. Dispersion modelling not conducted for facilities continuously flaring sour gas greater than 10 mol/kmol.

M 13. Venting practices not conducted in accordance with *Guide 60*.

7. Drain System

U 1. Vessel drain terminates to pit.

U 2. Vessel drains onto ground.

U 3. Drains not plugged or tied into tankage.

8. Signage/Security

U 1. No or improper identification sign.

U 2. No H_2S sign (H_2S concentration exceeds 10 ppm).

U 3. No flammable warning sign on sweet well.

U 4. Fencing not adequate as per OGC Regulations, Section 8.170.

U 5. H_2S sign at a sweet facility.

9. Pop Tank

M 1. No pop tank where required.

M 2. No automatic control system installed where required.

U 3. Pop lines not self-draining and/or tied down.

U 4. Pop lines not terminating in upper third of pop tank.

U 5. Pop tank capacity not equal to unattended production (*Guide 55*).

U 6. Production tank used as pop tank (no approval).

U 7. No isolation valve installed between high-pressure shutdown device and pressure vessel.

U 8. Pop tank leaking fluids.

U 9. Pop tank not sufficiently vented.

U 10. High-pressure shutdown device not tested as required.

10. Emergency Shutdowns

M 1. No surface shutoff valve where required.

M 2. No subsurface shutoff valve where required.

11. Compressor Installation

M 1. No approval for permanent compressor.

M 2. Temporary approval for compressor expired.

U 3. Exhaust stack height does not conform to requirements.

U 4. No catalytic converter where required.

M 5. No approval for temporary compressor (operating more than 21 days).

12. Storage Requirements (references are to *Guide 55*)

A. General storage practices (Section 3)

U 1. Materials not consumed within two years.

U 2. Oilfield wastes/empty barrels stored more than one year or temporary storage exceeds three months.

M 3. Temporary single-walled aboveground tank not diked (unless operation qualifies for it to be optional).

U 4. Temporary tank not diked or not emptied and removed from site within 72 hours of completing the operation (drilling, completions, testing, or servicing operations).

M 5. Contaminated material stored directly on the ground.

B. Storage areas/facilities (Section 3.6)

U 6. Not readily accessible for fire fighting and other emergency procedures.

U 7. Located on a floodplain.

U 8. Located within 100 m of normal high-water mark of a body of water, permanent stream, or water well used for domestic purposes.

C. Aboveground storage tank(s) with an internal volume less than 5 m^3 (Section 5.1)

U 9. Not externally coated or made from weather- and corrosion-resistant material.

D. Aboveground open-topped, nonmetallic tanks less than 30 m^3 (Section 5.2)

U 10. Open-topped, nonmetallic tank(s) used for storage of produced water from gas wells producing from other pools rather than Milk River, Medicine Hat, or Second White Specks.

U 11. Tank integrity tests not completed on five-year basis.

E. Aboveground storage tank(s) with internal volume equal to or greater than 5 m^3(Section 5.3)

U 12. Steel tank(s) not externally coated.

U 13. Spill control device(s) not installed/inadequate.

U 14. No measures in place to prevent overfilling of tanks.

M 15. No tank dike where required.

U 16. Liner not installed where required/insufficient liner.

U 17. Tank loading/unloading areas not designed to contain spills or leaks.

U 18. Tank dike(s) deteriorating, developing leaks, or unable to withstand hydrostatic head.

U 19. Insufficient tank dike capacity.

U 20. Tank dike(s) contain openings (e.g., open dike drains).

U 21. Impervious liner does not cover the dike and the area within the dike, not keyed into dike walls.

U 22. Aboveground tank not tested at the required five-year frequency/operator cannot demonstrate tank integrity. **Note:** Integrity tests are required only for pre-1996 sites that do not have full secondary containment. Option is to verify integrity and repeat every five years or retrofit tank farm with liner and dike—full secondary containment.

U 23. Inadequate leak detection methods.

U 24. Indoor aboveground storage tanks not surrounded by containment device and/or drain and collection tank with sufficient capacity.

F. Double-walled tanks with internal volume greater than 5 m^3 (Section 5.33)

U 25. No measures in place to prevent overfilling of tank(s) (alarms/automatic shutoffs).

U 26. Spill control device(s) not installed/inadequate.

U 27. No system to monitor interstitial space.

U 28. No protection from vehicular damage (e.g., barriers to protect tank from vehicular damage, controlled access to site).

U 29. Automatic shutdown system/interstitial space not checked on a monthly basis.

G Underground storage tank(s) including associated piping (Section 6)

M 30. No leak detection and secondary containment where required.

M 31. Underground storage tank(s) not double walled (tanks installed after January 1, 2002).

M 32. Newly installed tank(s) and associated piping not tested prior to service.

U 33. Steel tank(s) not cathodically protected or externally coated.

U 34. Tank loading/unloading areas not designed to contain spills or leaks.

U 35. Spill control devices not installed/inadequate.

U 36. Tank breathing vents not designed to prevent fluid overflow.

U 37. No measures in place to prevent overfilling of tanks.

U 38. Underground tank(s) not tested at the required three-year frequency/operator cannot demonstrate tank integrity. **Note:** Integrity tests required only for pre-1996 sites that do not have full secondary containment. Option is to verify integrity and repeat every three years or retrofit tank with full secondary containment.

H. Storage containers with combined volume greater than 1 m^3 on site (Section 7)

U 39. Insufficient or no secondary containment (lined compound with dikes/curbs and collection trays).

U 40. No weather protection where required.

I. Bulk pads for the storage of solid materials (Section 9)

U 41. Using concrete as primary containment where there is a potential for stored materials to leach (bulk pads constructed after October 31, 2001).

U 42. Not constructed of compacted clay, synthetic liner, concrete, or asphalt.

U 43. No continuous curb on three sides and/or curb height not minimum 15 cm.

U 44. No leachate collection or leak detection system where required.

J. Inspection, monitoring, and record keeping (Section 10)

U 45. Inventory records for last two years not available.

U 46. Records of inspection and corrosion monitoring programs not available.

U 47. Other records not available where required.

U 48. Applicable approvals, licences, or permits not on site or at field/plant offices.

K. Withdrawal of storage tanks from service (Section 12)

U 49. Aboveground/underground tanks out of service do not meet the requirements.

13. Vapour Recovery (facilities greater than 10 mol/kmol or where required)

M 1. Vapour recovery equipment inadequate/not operable (e.g., flame arrester plugged, thief hatch not sealing, venture not working, vapour recovery compressor down).

U 2. Overhead vapours flared without approval.

14. Odour Emissions

M 1. H_2S emissions off lease (identify source and cause).

M 2. Maximum permissible concentration for H_2S/SO_2 being exceeded (identify source and cause).

U 3. Other emissions off lease (hydrocarbon, mercaptans, etc.).

M 4. Failure to immediately notify the EUB of H_2S emissions off lease.

15. Smoke Emissions

U 1. Recurring smoke emissions from flare stack.

16. Noise Emissions

M 1. Facility exceeding permissible sound levels.

17. Waste Management (references are to *Guide 58*)

M 1. Waste disposal to facility not authorized to accept it (Section 2.1).

M 2. Dangerous oilfield waste (DOW)/dangerous waste/hazardous waste imported to EUB-approved facilities from outside Alberta. Other wastes (non-DOW) accepted at facility without prior EUB approval (Section 3.0).

U 3. Waste-tracking system not maintained cradle to grave (includes all subcontractors) (Sections 4.0, 7.0, 9.0, 9.2.2(g)).

M 4. Oilfield wastes mixed for the purpose of dilution to avoid regulatory requirements (Section 5.5).

S 5. Banned oilfield wastes injected into pipeline system (Section 6.1).

U 6. EUB manifests not completed or completed improperly for DOWs transported on public roads (Section 7.1). Note exceptions: See Section 8.2.

U 7. Waste-tracking system/manifests not retained for two years (Sections 8.9, 9.2).

U 8. Waste management area not adequately fenced to prevent public and wildlife access (Section 11.3).

M 9. Land treatment area at approved facilities received more than one application.

M 10. Land treatment area at approved facility

   a. received waste not susceptible to biodegradation and/or creates offensive odours at site boundaries

   b. slope exceeds 5 per cent and area less than 100 m from any permanent body of water used more than five years

   c. application of waste occurred between October 15 and April 30, during rainfall periods or when soil is saturated with water, ice covered, snow covered, or frozen (Section 16.2)

U 11. No supporting information for one-time biocell/biopile at existing facility (Section 16.3).

M 12. Small batch feed incinerator on lease

- a. not designed in accordance with Section 17.4.3
- b. burning wastes other than waste types I, II, and III
- c. burning other than disposable filters
- d. incineration occurring within 1.5 km of any residence or public facility (without EUB approval) (Section 17.4)

M 13. Mobil Thermal Treatment Unit in operation without

- a. notifying landowners/residents within 1.5 km at least 30 days prior to commencement of operations
- b. notifying EUB field centre 48 hours prior to commencement of operations (Section 17.5)

M 14. Oily by-products from other than heavy oil production applied to road surfaces (Section 29.0)

18. Housekeeping

U 1. Oil or saltwater staining on lease.

U 2. Garbage or loose debris not controlled on site.

U 3. Vegetation posing a fire hazard on dikes or firewalls.

19. Spills

M 1. Spill on/off lease not adequately controlled/cleaned up.

S 2. Unaddressed spill into water.

M 3. No notification of reportable spill to EUB.

20. Pits

M 1. Flare pit used at facility constructed after July 1, 1996 (*IL 96-4* and *Guide 60*).

M 2. Pit containing produced fluids or process chemicals.

U 3. Evidence of produced fluid staining in pit.

U 4. Pit construction unsatisfactory.

M 5. Disposal of precipitation from pit unsatisfactory as per *Guide 58.*

U 6. Failure to upgrade facility construction prior to July 1, 1996, with appropriate flow shutoff or emergency containment device as per *IL 96-4* and *Guide 60.*

21. Surface Runoff Control

M 1. Lease not diked (where required).

U 2. Lease diking/grading inadequate (dike requires repair, open dike drain).

U 3. Conditions of AENV approval not met (EUB/AENV-approved facilities).

M 4. Release criteria in *Guide 55/Guide 58* not met prior to release.

M 5. Soil sterilants have migrated off lease.

22. Compliance with Other EUB Requirements

S 1. Facility operating without approval.

U 2. Facility not constructed or operating in compliance with other EUB requirements (identify).

U 3. Gas not conserved in a gas conservation area/excessive flaring of gas volumes.

U 4. Suspended facility not in accordance with EUB requirements.

U 5. No approval to change category or type of facility.

U 6. Flaring practices not in accordance with *Guide 60.*

M 7. Flare reductions during planned shutdowns and emergency events not in compliance with flaring requirements (oil batteries/solution gas plants) (*Guide 60*, Section 2.1.6).

M 8. No personal consultation/public notification where required.

U 9. EUB not notified of flaring event(s) where required.

23. Emergency Response Plan(s) (ERPs)

S 1. No approved site-specific ERP where required.

S 2. Safety equipment specified in ERP not installed.

M 3. ERP manual not updated yearly, exercises not conducted, or details not documented.

U 4. Operator not communicating with residents in the emergency planning zone.

M 5. Copy of ERP not readily available.

M 6. On-site operator representatives not familiar with ERP.

M 7. No corporate-level ERP where required.

Appendix 2 EUB Field Surveillance Enforcement Process and Ladder

The present *Informational Letter (IL) 99-4: EUB Enforcement Process, Generic Enforcement Ladder and Field Surveillance Enforcement Ladder* and its EUB Enforcement Process—Clarification document are to be replaced with a new, updated IL later in 2002.

In the interim, refer to *IL 99-4*, which is available on the EUB Web site at <www.eub.gov.ab.ca>.

When the new IL is issued, it will be available on the Web site. At that time, please insert the EUB Field Surveillance Enforcement Process and Ladders into *Guide 64* after this Appendix 2 page.

Appendix 3 Notification Policy – Field Operations Access to Unmanned Field Facilities

Introduction

The practices and procedures outlined in the EUB *Internal Guide 8: Safety Manual,* Section 300, are intended to provide a guide to individuals conducting on-site inspections. The practices and procedures are to be followed to eliminate or considerably reduce any associated risks encountered in the field.

Visual or Passive Inspection

- A visual or passive inspection involves a visual assessment of a facility and does not include the manipulation of any valves or taking of sour fluid levels or catching of samples.
- EUB staff may, at their discretion, notify company personnel prior to conducting a visual or passive inspection.
- The inspection may be conducted without a company representative or another EUB staff member being present.

Hands-on or Active Inspection

- The hands-on or active inspection may involve the making of connections to high-pressure wells or associated piping, manipulating valves, gauging sour fluid in storage tanks, or inspecting hatches on sour production tanks.
- EUB staff must not operate valves or equipment or perform any "hands-on" operations unless there is a threat to the public or prior approval has been received from a company representative, the inspector's Section/Team Leader, or a higher authority in the EUB. Appropriate company personnel on site should be requested to perform these operations as required.
- A company representative would likely wish to be present. If none chooses to be in attendance, the EUB staff may conduct the inspection in accordance with accepted practices and procedures.
- EUB policy requires two fully trained and qualified staff in both safety* and work procedures to be present when gauging or inspecting hatches on sour tanks, making all necessary high-pressure connections, and manipulating all valves that could affect production (preferably one company representative and one EUB staff, or two EUB staff). It is desirable to have a company representative present when making high-pressure connections and manipulating valves that may affect production.
- All work falling into the active inspection category may be completed at the direction of a Section/Team Leader or designate without prior operator notification in certain situations, including, but not limited to, investigations of fraud, theft, or other such serious infractions.

*Job performance training and valid certification in H_2S Alive, First Aid, and CPR.

Appendix 4 Lease Inspection System—Well Testing and Flaring Inspections

The Lease Inspection System (LIS) must be used for all wellhead lease inspections, including single well batteries, tied-in wells (physically and for accounting/reporting), and suspended and newly completed wells. Any inspections of well testing and flaring events must be recorded (documented) on the LIS. In the past, EUB field inspectors used the Facility Check Sheet to capture noncompliance items for wellheads, but we now have the Lease Inspection Category in our field surveillance enforcement ladders. There is some inspection item(s) overlap between LIS and the other audit/inspection categories, but it is important to remember **not** to record the same deficiency on both the Lease Inspection Form (see page 66) and the Facility Check Sheet. Again, there will be no escalating consequences (and/or "getting off the enforcement ladder") between the LIS and the Oil and Gas Production System (*Guide 64*).

Lease Inspection Check Sheet Items

Site Maintenance and Security

1. Identification sign
2. Warning signs
3. Site security procedures
4. Fencing
5. Wellhead visibility
6. Spacing
7. Housekeeping

Wellhead Equipment

8. Wellhead valves
9. Surface casing vent
10. BOPs and emergency shut-in devices
11. Well suspension

Environment

12. Spills and leaks
13. Waste management
14. Odours
15. Noise
16. Storage
17. Surface runoff control

Wellbore

18. Surface case vent flow
19. Gas migration
20. Packer isolation
21. Casing integrity
22. Well abandonment

Operations Compliant

23. Well testing and flaring
24. Notification and public consultation
25. Approval to operate

Unsatisfactory Items

Site Maintenance and Security

1. Identification Sign

U a) No or improper identification sign (OGC Regulations, Section 6.020).

2. Warning Signs

U a) No flammable warning sign at a sweet well (OGC Regulations, Section 6.020).

U b) Warning decals worn off/illegible.

U c) No H_2S warning sign at sour well (> 10 ppm) (OGC Regulations, Section 6.020).

U d) Sign has not been erected to alert public of operation in progress (well testing/flaring requirement).

U e) Symbols on sign must be of the size, design, and colour shown on Schedule 12 (OGC Regulations, Section 6.020(10)).

3. Site Security Procedures

U a) Operation required to be attended 24 hours/day but left unmanned (well testing/flaring requirement).

U b) Gate left unlocked (if required as per OGC Regulations, Section 8.180(2)).

U c) Site security requirements not met for suspended well (*ID 90-4*).

U d) Operation left in unsafe condition.

4. Fencing

U a) No or inadequate fence around well.

U b) Fence does not meet requirements of *ID 98-2*.

M c) Pumping well within 800 m of public development and does not have fence as per OGC Regulations, Section 8.180(2).

5. Wellhead Visibility

U a) The wellhead is not conspicuously marked so that it is visible in all seasons (*ID 98-2*).

6. Spacing

U a) Tanks to surface improvement (other than roads) less than 60 m.

U b) Fire less than 50 m from a well.

U c) Fire less than 50 m from a hydrocarbon liquid storage tank.

U d) Fire less than 50 m from a source of ignitable vapours.

U e) Hydrocarbon liquid tanks to well less than 50 m.

U f) Flame-type equipment to well less than 25 m.

U g) Flame-type equipment to source of ignitable vapour less than 25 m.

U h) Flare pit or stack less than 100 m from surface improvement except roadway.

U i) Internal combustion engine exhaust within 25 m of a well, process vessel, storage tank, or source of ignitable vapour has flame emergence (OGC Regulations, Section 8.090(9)(a)).

M j) Flare stack less than 100 m from an occupied residence.

U k) End of exhaust pipe from internal combustion engine is closer than 6 m to the vertical centre line of the well projected upward and is not directed away from the well (OGC Regulations, Section 8.090(9)(b)).

7. Housekeeping

U a) Garbage or loose debris not controlled on site.

U b) Vegetation posing a fire hazard.

U c) Oil or salt water staining on lease.

Wellhead Equipment

8. Wellhead Valves

M a) Well does not have a master valve, as required by *ID 98-2*.

M b) Valve(s) of insufficient rating for operating pressure.

M c) A flowing well at which the H_2S concentration exceeds 5% does not have two master valves (OGC Regulations, Section 7.050(3)).

M d) Valves on sour well not sour service.

M e) No subsurface valves – shut-in valves (OCG Regulations, Section 7.050(1)).

9. Surface Casing Vent

U a) Well does not have a surface casing vent where required.

U b) Surface casing vent inadequate (OGC Regulations, Section 6.100).

U c) Vent is closed.

10. BOPs and Emergency Shut-in Devices

M a) Well not equipped with hydraulic rod blowout preventer (BOP) and environmental BOP, as per *ID 98-2*.

M b) Pumping well not equipped with pressure switch.

M c) A flowing well is located closer than 100 m to normal high-water mark of a body of water and does not have an automatically closing wellhead valve (OGC Regulations, Section 8.060(a)).

M d) No packer and subsurface automatic shut-in valve on a well that is located closer than 100 m to normal high-water mark of a body of water (OGC Regulations, Section 8.060(b)).

M e) A flowing well at which the H_2S concentration exceeds 5% is located within 800 m of a dwelling or 8 km of a city or town and does not have a subsurface automatic shut-in valve (OGC Regulations, Section 7.050(7)).

11. Well Suspension (*ID 90-4*)

U a) All wellhead valves are not chained and locked.

M b) Well not suspended, as required by *ID 90-4*.

Environment

12. Spills and Leaks

M a) Spill on lease not adequately controlled/cleaned up.

M b) Spill off lease not adequately controlled/cleaned up.

S c) Unaddressed spill into water.

M d) No notification of spill to EUB (if reportable).

U e) Sweet gas leak not addressed.

13. Waste Management

M a) Land treatment area does not meet criteria of *Guide 58.*

M b) Biocell/biopile does not meet criteria of *Guide 58.*

U c) Off-site land treatment initiated without proper notification to EUB (*IL 98-2*).

M d) Land treatment area received more than one application.

M e) Waste disposal to facility not authorized to accept it.

U f) Drilling waste management not as per *Guide 50.*

U g) Other waste not managed appropriately.

M h) Fracture waste not managed appropriately.

14. Odours

M a) H_2S emissions off lease.

M b) Maximum permissible concentration of H_2S/SO_2 exceeded and violation detected and not addressed.

U c) H_2S/SO_2 exceedance/violation not reported to EUB (well testing/flaring requirement).

U d) Other emissions off lease (hydrocarbon, mercaptans, etc.).

15. Noise

M a) Temporary operation at well site exceeds permissible sound levels (well testing/flaring requirement).

M b) Operation at well site exceeds permissible sound levels (*ID 99-8*).

16. Storage Requirements (*Guide 55*)

U a) Permanent aboveground steel tanks not externally coated.

M b) No tank dike(s) where required.

U c) Tank dike of inadequate design or in poor repair.

U d) Insufficient tank dike capacity.

U e) Insufficient secondary containment or weather protection for storage containers.

M f) Oilfield waste materials not properly stored/contained.

U g) Temporary storage exceeds three months.

U h) No tank dike, and operator has not emptied the tank or removed it from the site within 72 hours of completing the operation.

17. Surface Runoff Control

M a) Lease not diked where required.

U b) Lease diking/grading inadequate.

M c) Release criteria in *Guide 58* not met.

M d) Soil sterilants have migrated off lease.

Wellbore

18. Surface Casing Vent Flow (*ID 99-3*)

U a) Surface casing vent flow (SCVF) gas.

M b) SCVF gas with liquids

19. Gas Migration

U a) Active gas migration identified.

M b) Active gas migration with liquids.

20. Packer Isolation (*IL 94-18*)

This subsection will currently not be used but could be developed for future inspections.

21. Casing Integrity

This subsection will currently not be used but could be developed for future inspections.

22. Well Abandonment (*Guide 20*)

M a) Leaking abandoned well not immediately reported to EUB Field Centre and reabandonment program not submitted within 30 days.

U b) Reabandonment not completed within 12 months of initial downhole operations (*Guide 20*, Section 1.2, page 10).

M c) Incorrect plug placement may result in interzonal communication or contamination of usable water zones (*Guide 20*, Section 1.2, page 8).

U d) Well abandoned within "Program 4 – Problem Region" and EUB Field Centre not notified within 24 hours.

M e) Failure to leave well open for visual inspection by EUB staff prior to cutting and capping in "Program Area 4 – Problem Region."

M f) Failure to conduct gas migration survey prior to cutting and capping abandoned well in "Program Area 3 – Problem Region."

M g) Abandonment procedures not in accordance with guidelines.

Operations Complaint

23. Well Testing and Flaring

M a) Flaring performance requirements not met (*Guide 60*, Section 7).

M b) Venting practices not in accordance with *Guide 60* or local Field Centre agreement.

M c) Flare volume in exceedance of routine flare volume allowance without approval (Section 3.8 of *Guide 60*, February 2001 Updates).

M d) Testing sour gas well (>5% H_2S) or critical sour gas well without required permit (Section 3.4 of *Guide 60*, February 2001 Updates).

M e) Failure to comply with special conditions of permit or approval.

24. Notification and Public Consultation (Well Testing and Flaring Requirements)

U a) EUB not notified of flaring or venting, as required by *Guide 60.*

M b) Residents within required radius not notified of flaring or venting (*Guide 60*).

U c) Operator not communicating with residents in an emergency planning zone.

M d) Operator does not advise landowner of off-lease spill/odour.

U e) Operator not adequately addressing public complaints/concerns.

S f) No approved site-specific emergency response plan (ERP) where required.

S g) Safety equipment specified in ERP not installed.

M h) Copy of ERP not readily available.

M i) Operator on-site representative not familiar with ERP.

25. Approval to Operate

M a) Well being used for injection or disposal without EUB approval.

M b) Injection/disposal well not operating in compliance with approval.

S c) Well operating after closure order issued.

EUB

Lease Inspection Form

(document version)

INSPECTOR:

Blank – Not Applicable / Not Inspected

X - Satisfactory

U - Minor

M - Major

S - Serious

- **Major and Serious non-compliance issues require manual letter generation.**
- **Minor non-compliance issues will generate an automatic letter.**

	Site Maintenance and Security							Wellhead Equipment				Environment						Wellbore					Operations Compliant			
WELL IDENTIFIER	Identification Sign	Warning Signs	Site Security Procedures	Fencing	Well Head Visibility	Spacing	Housekeeping	Well Head Valves	Surface Casing Vent	BOP's & Emergency Shut In Devices	Well Suspension	Spills and Leaks	Waste Management	Odours	Noise	Storage	Surface Run Off Control	Surface casing Vent Flow	Gas Migration	Packer Isolation	Casing Integrity	Well Abandonment	Well Testing and Flaring	Notification & Public Consultation	Approval to Operate	COMMENTS
LE LS SE TWP RGE M ES Date Day Month Year																										
LE LS SE TWP RGE M ES Date Day Month Year																										
LE LS SE TWP RGE M ES Date Day Month Year																										
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Appendix 5 Tank Gauging Requirements

Tank gauging requirements, as stated in the *API Manual of Petroleum Measurement Standards*, Chapter 3: Tank Gauging, Section 3.1A: Standard Practice for the Manual Gauging of Petroleum and Petroleum Products (first edition, December 1994), are as follows:

3.1.A.9.1.1 Manual gauging shall require three consecutive readings to be within a range of 3 millimetres (1/8 inch). If two of the three consecutive readings are identical, this reading shall be reported to the nearest 1 millimetre if metric gauge tapes are used or to the nearest 1/8 inch if customary gauge tapes are used. If the gauger must use all three readings, the three readings should be averaged, and this average reported to the nearest 1 millimetre (for metric tapes) or 1/8 inch (for tapes with customary units). For crude oil lease tanks of 1000 barrel nominal capacity or less, the span will be increased to 5 millimetres (1/4 inch), and should be reported to the nearest 5 millimetres (or 1/4 inch).

To meet accuracy requirements for oil/condensate measurement, the tank must be sized as follows:

- Where uncertainty requirements are ± 0.5 per cent, the volume (V) in m^3 of the liquid being measured must be equal to or greater than the square of the tank diameter (d) in metres (m) times 0.92 (± 0.5 per cent uncertainty coefficient); $V \geq 0.92\backslash d^2$.
- Where uncertainty requirements are ± 1.0 per cent, the volume (V) in m^3 of the liquid being measured must be equal to or greater than the square of the tank diameter (d) in metres (m) times 0.39 (± 1.0 per cent uncertainty coefficient); $V \geq 0.39\backslash d^2$.

See *IL 90-6* and *IL 92-8* regarding specifics of handling trucked emulsion/oil.

Battery/Well Test Tank Diameter Sizing Guidelines

Tank gauging is subject to errors or uncertainty in the reading of the tape (in and out) as well as in the accuracy of the tape itself (in and out). The error in total volume measurement can be minimized by maximizing the height of the fluid column being gauged. Given a specified tank diameter and knowing what uncertainty is acceptable (gauge reading to the nearest ¼" or 5 mm, according to API MPMS, Section 3.1A), the required test volume can be estimated. Conversely, knowing the rates of the wells (i.e., test volume), the required tank diameter can be calculated.

To meet accuracy requirements for total test fluid measurement, the minimum test fluid volume or maximum tank diameter should be determined as follows:

$$V >= a \text{ x } d^2 \qquad \text{or} \qquad d = < \text{Sqrt}\ (V/a)$$

Where:

V = test volume in m^3
d = test diameter in metres
a = accuracy coefficient
= 0.39 for 1.0% uncertainty

Have some flexibility when applying this rule of thumb. Practicality would suggest that requirements for low-productivity wells might be less than the guidelines suggest.

Note that test tank volumes must also be temperature corrected.

Appendix 6 Shop Calibration of Liquid Meters

EUB FACILITY DIVISION – INTERNAL MEASUREMENT POLICY

Title: Shop Calibration of Liquid Meters

Policy No.: IMP-07
File No.: 16-0308
Date: 12 August 1996

Owner:

Introduction

Part 14 of the Oil and Gas Conservation Regulations (the Regulations) requires that liquid meters used for measurement of test oil, total oil (i.e., group) and condensate production be calibrated in the field at operating conditions. However, in *ID 91-3, Heavy Oil/Oil Sands Operations* we amended section 14.110 to permit shop calibration of meters used for measurement of test heavy oil (920 kg/m^3 density or greater) production. In addition, the American Petroleum Institute *Manual of Petroleum Measurement Standards* (*API-MPMS*) *Chapter 20.1: Allocation Measurement* presented shop calibration of test oil meters as an acceptable procedure. We therefore believe it is appropriate to define the circumstances where shop calibration for meters used for measurement of conventional oil and condensate is permissible.

Administration

Facility Division staff may supply a copy of this policy to any company requesting additional information on shop calibration. An operator may perform a shop calibration of a liquid meter without application to the EUB provided the following conditions are met.

- Prior to the initial shop calibration of a meter that meets the rate qualifications set out below, the operator shall conduct an inspection of the installation according to the requirements in Attachment A.

- A calibration shall follow a documented procedure that takes into consideration the items outlined in Attachment B.

- A shrinkage factor for the oil measured by a test oil meter shall be determined by lab or computer simulation or according to the procedure described in Section 1.7.4 of *API-MPMS, Chapter 20.1: Allocation Measurement*. The net oil and net water volumes shall be calculated in accordance with Section 1.9.5 of *API-MPMS, Chapter 20.1*.

- All inspection and calibration results shall be recorded and made available for inspection by EUB staff upon request.

Shop calibration of a meter used for measurement of condensate is permissible when:

- the measured condensate rate is less than 2 m^3 per day, or
- the measured condensate rate is more than 2 m^3 per day but less than 3 m^3 per day and the gas equivalent volume of condensate is less than or equal to 3 per cent of the measured gas volume.

Shop calibration of a meter used for test measurement of conventional (i.e., less than 920 kg/m^3 density) is permissible when:

- the average metered rate (i.e., total fluid for a 2-phase test separator and liquid in oil leg for 3 phase) of all wells being tested through the meter is less than 2 m^3 per day and no well exceeds 4 m^3 per day.

Note that Section 14.140 of the Regulations permits shop calibration of meters used for the measurement of water.

Discussion

The calibration of a liquid meter is needed for:
- detection of meter damage,
- verification of proper metering system installation,
- adjustment of mechanical performance changes over time,

and for a live (at equilibrium vapour pressure) test oil meter is also needed for:
- adjustment of oil volume to stock tank conditions, and
- reduction of errors due to fluid differences between wells.

Sections 14.090 and 14.110 of the Regulations require operators to calibrate a positive displacement meter, turbine meter, or coriolis mass flow meter that is used to measure condensate or test oil in the field at operating conditions. A field calibration is the best method to achieve the above needs. However, when the liquid volume is low, we recognize that the time to perform a field calibration may be unreasonably long and therefore economically onerous.

Our primary goal with condensate and test oil measurement is to ensure royalty, equity, and engineering concerns are met. Essential to this is to avoid large errors that occur for a long period. The largest errors can occur through meter damage and improper metering system installation. A field calibration will normally detect these errors, and therefore, is a control on how long an error will be undetected. A shop calibration will normally detect meter damage but not installation problems. The metering system can be inspected for proper installation and operation as part of the calibration procedure; however, we have doubts as to how diligently the operator will follow the procedure and how effective these procedures are at detecting problems when followed. Despite these concerns, we believe that the increased uncertainty for shop calibration represents a low risk to the reservoir, equity, and royalty concerns when the metered condensate rate is less than 2 m^3 per day or when the average metered rate of all wells being tested through a test oil meter is less than 2 m^3 per day and no well exceeds 4 m^3 per day. In addition, where the gas equivalent volume of liquid is less than or equal to 3 per cent of the metered gas volume, the magnitude of the measurement uncertainty for the condensate has minimal effect on the uncertainty for the total volume (i.e., gas volume plus gas equivalent volume of liquid). However, the condensate represents significant monetary value and we believe an upper maximum of 3 m^3 per day is justified.

The calibration of test oil meters is complicated by the additional needs of accounting for gas in solution to obtain a stock tank volume and reducing errors due to fluid differences between wells. Shop calibration does not easily accommodate these needs, and therefore, we should advise operators that our preference is to relax the expectations for an in-line calibration to allow the calibration to occur in a reasonable time. Accordingly, operators should be given the following options (in order of preferred relaxation) to modify their procedure for the calibration of test oil meters:

- Swing several wells at one time through separator for each run.
- Degas one run only and apply the shrinkage factor to other runs without degassing.
- Use same well (i.e., highest rate) for all runs.
- Make three runs only.

These options should be limited to a meter that meets the shop calibration rate requirements.

Attachment A — Requirements for Initial Shop Calibration of a Liquid Meter

If excessive pressure drop occurs either upstream of or through the meter, gas will flash from the liquid and the meter will yield volumes with large errors. The meter must be installed upstream of a snap acting type control valve and the pressure drop from the separator to immediately downstream of the meter should not exceed 10 per cent of the separator operating pressure. The operator shall measure the pressure drop and if it exceeds this limit shall:

- replace the meter and/or control valve with ones properly sized to minimize the pressure drop through the meter,
- relocate the meter further below the liquid level in the separator, and/or
- reduce the piping distance between the separator and the meter.

If excessive pressure drop still occurs, the operator shall conduct both a field and shop calibration of the meter to ensure the results are comparable.

The operator shall keep a record of inspection results and any action taken to improve the measurement system.

Attachment B — Guidelines for Shop Calibration of a Liquid Meter

A proper shop calibration should consist of a field inspection of the installation, measuring, and recording actual operating conditions, using an adequate calibration procedure, applying corrections to the determined meter factor if necessary, and maintaining complete and accurate documentation.

B.1 Field Inspection

Prior to removal of a meter from service for a shop calibration, the operator should verify that:

- the flow rate and pressure drop through the meter are within the manufacturer's recommended operating range (see Appendix A of EUB *Guide 46: Production Audit Handbook*).
- the dump valve is snap-acting and fully open in 3 to 4 seconds, and
- the dump valve does not leak (i.e., the meter must not register any flow between dumps).

The operator should also measure and record the separator operating pressure and temperature and take a pressurized sample of the liquid for shrinkage factor determination. All recorded data should accompany the meter to the calibration site.

B.2 Calibration Procedure

The following procedures are recommended for a shop calibration.

1. The calibration should be performed at a similar flow rate (within 10 per cent), pressure, and temperature to the actual operating conditions.
2. The piping configuration for the calibration should be similar to that used in the field.
3. Corrections for temperature and pressure of the proving fluid should be made if necessary.
4. The calibration should consist of four runs with a valid proof obtained when the difference between the highest and lowest value is less than 0.5 per cent of the average of the 4 runs.

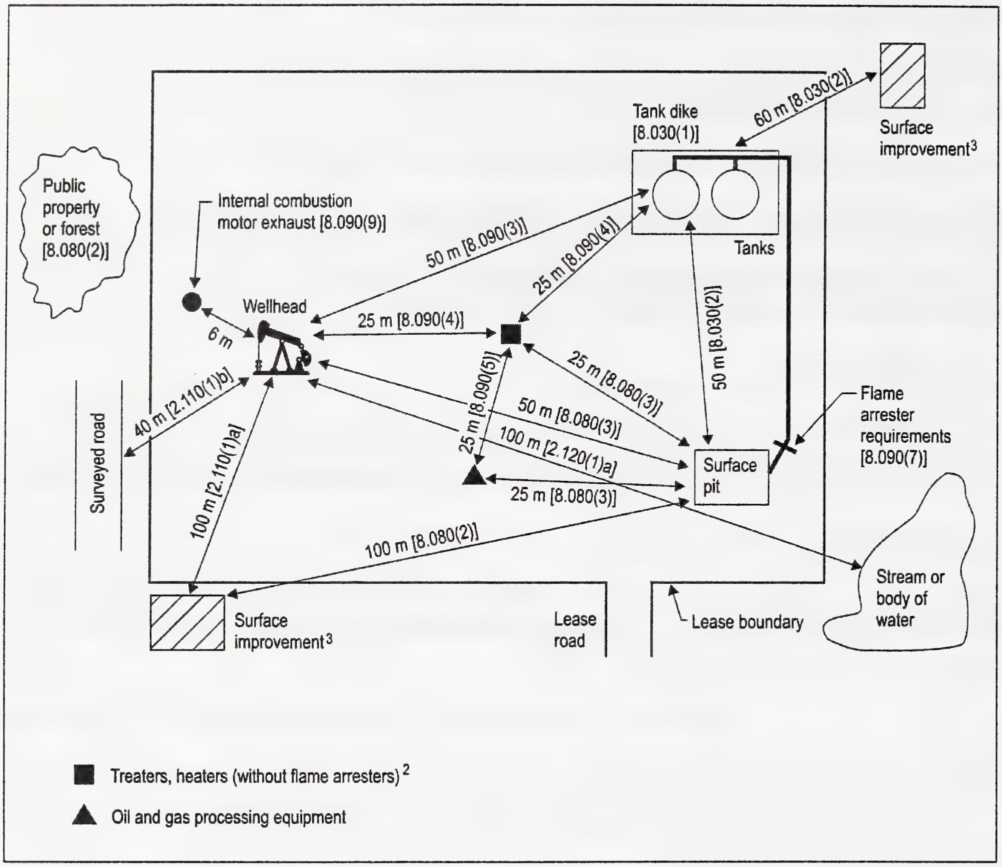
B.3 Correction Factors

If water is used as a calibration fluid, the meter factor may need to be corrected for the density and viscosity of the liquid being measured. Operators must obtain verification that density and viscosity effects are minimal or obtain and apply correction factor formulae from the manufacturer of the meter.

B.4 Documentation

The operator shall keep a record of all calibration results (flow rate, temperatures, pressure, and volume calculations) and make them available for inspection by EUB staff upon request. This calibration report should clearly state that the meter was shop calibrated.

Appendix 7 Spacing Diagram



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[1] The spacing requirements illustrated here are as specified in the Oil and Gas Conservation Regulations sections indicated within square brackets alongside or underneath each measurement.

Note that there is no smoking within 25 m of a well, separator, oil storage tank, or other unprotected source of ignitable vapour [Section 8.120(1)].

[2] Treaters and heaters without flame arresters are not to be housed in the same building unless air intakes, flues, vents, ignitable vapours, etc., are vented outside above roof level and the building is cross-ventilated [8.090(6)a,b,c]. Treaters and heaters with flame arresters must also be 25 m from a well, oil storage tank, or other source of ignitable vapour [8.090(5)].

[3] "Surface improvement" means a railway, pipeline or other right-of-way, road allowance, surveyed roadway, dwelling, industrial plant, aircraft runway or taxiway, building used for military purposes, permanent farm building, school or church [1.020(1)28]. Lease roads are not considered a surface improvement.

Appendix 8 Guidelines for Use of Tank Heaters

The use of tank heaters in heavy oil areas is permitted under the guidelines set out in *ID 91-3*: *Heavy Oil/Oil Sands Operations.*

The use of tank heaters in conventional oil is not recommended. Generally the EUB wants to discourage the use of heated tanks in place of treaters; however, it must be receptive to considering the economics of a marginal operation. Where the tank heater is proposed/used for oil shipping or to avoid water-freezing problems, inspection staff are expected to use the following criteria in assessing requests for the use of tank heaters:

1) The density of the oil is >800 kg/m^3 (API 45°).
2) The pour point temperature of the oil is -15°C or higher.
3) There is a mandatory flame arrester.
4) The total daily gas volume from the stock tank vented to atmosphere does not exceed 500 m^3/day. All sources of gaseous vapours, such as thief hatch, load lines, and vent lines, must be directed away from the tank heater due to fire/explosion potential.
5) The maximum expected temperature of the fluid in the stock tank does not exceed 30°C.
6) Suitable burner-lighting (start-up) procedures are in place. If not, recommend use of enclosed burner igniters.
7) The fire tube must be submersed in liquid when the tank heater is in operation. A minimum of 0.5 m of liquid must be above the fire tube.

Safety is the paramount concern. If there is any reason to believe that the heaters are creating a hazard, they must be disconnected immediately.

Appendix 9 Flaring Guide for the Upstream Petroleum Industry*

As part of facility inspections of oil batteries and gas plants, EUB staff check to determine that cutbacks have been within specified guidelines, proper logs are being maintained, and the correct procedures are being used to notify residents. Standard EUB enforcement processes will be utilized if operators are not taking reasonable steps to comply.

Solution Gas Flaring at Conserving Batteries

Nonroutine solution gas flaring is any planned or emergency event that results in additional flaring beyond the normal flare volumes at a gas conserving battery. Nonroutine flaring may result during upsets, maintenance, and repairs at a battery or the downstream pipelines and solution gas plant.

Shutdown Category	Duration (hours)	Operational Requirements
Planned	<4	Operators will make all reasonable efforts to reduce battery inlet gas volumes by 50% of average daily production over the previous 30 days.
	>4	Operators will make all reasonable efforts to reduce battery inlet gas volumes by 75% of average daily production over the previous 30 days with the following conditions: • Production rates will be sufficient to keep equipment operating safely and within minimum design turndown range. • Public, including residents within 500 metres, interested individuals, and people sensitive to emissions at the battery, must be notified at least 24 hours before the planned flaring event. • The appropriate EUB Field Centre must be notified prior to the planned shutdown of both the shutdown and any unresolved public complaints. • The appropriate EUB Field Centre must be notified if the event meets reporting requirements identified in *IL 98-1*, Section 4.4.
Emergency or Plant Upset	<4	No reduction in battery inlet is required.
	>4	Operators will make all reasonable efforts to reduce battery inlet gas volumes by 75% of average daily production over the previous 30 days with the following conditions: • Production rates will be sufficient to keep equipment operating safely and within minimum design turndown range. • Public, including residents within 500 metres, interested individuals, and people sensitive to emissions at the battery, must be notified as soon as practical during the flaring event. • The appropriate EUB Field Centre must be notified within 10 days of the flaring event of any unresolved public complaints. • The appropriate EUB Field Centre must be notified if the event meets reporting requirements identified in *IL 98-1*, Section 4.4.
Repeat Nonroutine Flaring		Operators must investigate causes of repeat nonroutine flaring and take steps necessary to eliminate or reduce the frequency of such incidents. • Operators must notify the EUB of unresolved public complaints regarding repeat flaring within 10 days of the complaint.

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* Excerpts from *Guide 60*.

Nonroutine solution gas flaring at conserving batteries falls under three categories, as outlined in *Guide 60*, which defines the operational requirements for each shutdown type as a function of flaring incident duration. These requirements are effective 1 January 2000.

Note:

- Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery that result in nonroutine flaring at a battery.
- Repeat nonroutine flarings are recurring events of similar cause at a conserving battery during a 30-day period.

Gas Plant Flare Volume Limits

The EUB expects operators of gas plants to operate so that a minimum of gaseous hydrocarbons and other gases are flared. Operators must not flare gaseous hydrocarbons in excess of 1.0 per cent in the first year of operation and 0.5 per cent of the total volume of raw gas delivered to gas processing plants in subsequent years.

Enforcement

Noncompliance by Licensee	Enforcement Action
Failure to meet flaring requirements for conserving batteries or gas plants	Advise the company of the noncompliance event. Instruct a senior company representative with provincial authority to • provide a written explanation of why the noncompliance event occurred, • provide a written action plan to ensure that it does not occur again, and • confirm in writing compliance at all similar sites and operations. Advise, in writing, the senior company representative of the consequences for continued or repeated noncompliance. Initiate or add to the noncompliance record in the EUB work group.
Failure to meet enforcement requirements	Issue formal order to comply. Enact the "Refer" status on the EUB Corporate Data Information System, which means further development plans will be reviewed by the EUB in considering the company's noncompliance record.

If in the opinion of the EUB a noncompliance causes odours above allowable limits or has unacceptable impacts on the public, the operations may be suspended if the impacts cannot be resolved.

Summary

There may be areas in the province where the EUB may decide that solution gas flaring will be reduced due to unique local environmental or land use sensitivities, even though normal economic thresholds are not met. The EUB may issue or revise a gas conservation order requiring all producers within a specific geographical area to conserve the gas.

Appendix 10 General Requirements for Containment Devices[1] (*Guide 55*, Table 2)

Primary containment device/size[2]	Section in *Guide 55*[3]	Design and construction	Secondary containment	Leak detection	Weather protection
Aboveground tank (1-5 m^3)[4]	5.1	Supplier specifications. Nonleaking hoses, fittings, and nozzles. Spill control devices.	Not required.	Monthly visual inspection.	External weather-protective coating or made from a weather-resistant material.
Aboveground open-topped nonmetallic tanks (<30 m^3)	5.2	Supplier specifications.	Not required.	Monthly visual inspection. Integrity verified every 5 years.	Not applicable.
Single-walled aboveground tank (>5 m^3)[4]	5.3.1 5.3.2	Cathodic protection in corrosive environments. External coating for steel tanks and internal coating in corrosive environments. Spill control devices.	Graded containment area. Dike (or curbing for indoor tanks) capacity 110% of tank or 100% of largest tank plus 10% of aggregate volume if more than one tank. Impervious liner.	Monthly visual inspection. Sand over liner and leakage collection area.	External weather-protective coating or made from a weather-resistant material.
Double-walled aboveground tank (>5 m^3)[4]	5.3.1 5.3.3	Cathodic protection in corrosive environments. External coating for steel tanks and internal coating in corrosive environments. Spill control devices including overfill protection.	Double walls with interstitial space.	Monthly monitoring of interstitial space.	External weather-protective coating or made from a weather-resistant material.
Underground tank[4] (any size); includes tanks and sumps)	6	Integrity testing of tank and piping prior to servicing. External coating and cathodic protection for steel tanks. Possible internal coating. Spill control devices.	Double walls with interstitial space.	Monthly monitoring of interstitial space.	Not applicable.
Container or group of containers (≤1 m^3 total)	7	Not applicable.	Not required.	Monthly visual inspection.	Not required.
Container or group of containers (>1 m^3 total)	7	Compatibility between container and stored materials. Segregated areas.	Dike, curb, and/or collection tray with a capacity of 100% of largest container or 10% of aggregate volume, whichever is greater.	Monthly visual inspection.	Physical cover (e.g., covered container or roof) or protective coating.
Lined earthen excavation	8	Specific to facility. Spill control devices.	Impervious liner.	Weeping tile. Monitoring well. Monthly monitoring.	Specific to facility and material type.
Bulk pad (solid material)	9	Specific to facility.	Impervious liner. Containment curb or dike.	Specific to material type.	Specific to facility and material type.

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[1] Applies to new storage facilities constructed and operated after January 1, 2002. Applies to the permanent storage of produced water, crude oil, emulsions, condensates, chemicals, solvents, produced sand, lubricants other than for motor vehicle use, oilfield wastes, oily waste, and bitumen. Maximum storage duration should not exceed 2 years, except for oilfield wastes which should not exceed 1 year. All inventory records must be kept for 2 years. All leak-detection monitoring results must be kept for 5 years.

[2] Internal volume.

[3] See *Guide 55* section cited for more detailed information.

[4] Tank requirements apply unless the fluids being stored are waters that meet the surface discharge criteria (chloride < 500 mg/litre maximum; pH 6.0 to 9.0; no visible hydrocarbon sheen; and no other chemical contami[illegible]n) or are fluids that are infrequently stored in tanks and the tanks are emptied immediately.

Appendix 11 LPG Storage Vessel—CSA-B149.2-00 Code

The standard does not state that a dike is required around storage bullets. However, if one is in place the following codes must be followed:

5.9.1 When a cylinder is installed adjacent to a storage area for flammable or combustible liquids, protection such as diking, diversion curbs, or grading shall be provided to prevent any accumulations of these liquids under the cylinder.

5.9.2 When dikes surround a flammable or combustible liquid tank, a cylinder shall not be installed within the diked area and shall be located not less than 3 metres from the centre line of the dike.

5.9.3 A cylinder may be installed adjacent to a tank containing a combustible or flammable liquid providing the capacity of the tank of such liquid is 1150 litres or less. When the capacity of the tank of combustible or flammable liquid exceeds 1150 litres, the separation between the cylinder and the tank shall be a minimum of 6 metres.

6.1.6 When necessary, diking, diversion curbing, or grading shall be provided.

(a) To prevent any accumulation of flammable or combustible liquids under a propane tank, or

(b) To contain or divert any loss of liquid propane from a source of ignition.

Appendix 12 H_2S Odour Management Process

Purpose: To clarify off-site regulatory requirements for H_2S odour management.

For facilities ≥ 10 mol/kmol (1% H_2S), if an inspector or an air-monitoring unit detects H_2S odours off lease:

Off-site inspection/monitor results	Odour complaint/facility history	Action
Inspector/air monitor validates odours off lease.		• Licensee must control emissions immediately or suspend facility/operation until repairs can be made. • Licensee will be placed on EUB's Enforcement Ladder as a major noncompliance.

For facilities < 10 mol/kmol (1% H_2S), if an inspector or an air-monitoring unit detects H_2S odours off lease:

Off-site inspection/monitor results	Odour complaint/facility history	Action
Inspector/air monitor validates odours off lease.	• No complaint. • No complaint history (no odour complaints within last 12 months).	• Licensee must equip facility to control emissions within 30 days. • Failure to comply will result in suspension and major noncompliance.
	• Complaint received within 30 days of first inspection date.	• Licensee must control emissions immediately or suspend facility/operation until repairs can be made. • Failure to comply will result in suspension and major noncompliance.
Inspector/air monitor validates odours off lease.	• Initial (first) complaint.	• Licensee must control emissions immediately or suspend facility/operation until repairs can be made. • Failure to comply will result in suspension and major noncompliance.
	• Complaint received (documented complaint history on facility/ operation). • Previous odour mitigation requested by EUB.	• Licensee must suspend facility. • Licensee will be placed on EUB's Enforcement Ladder as a major noncompliance.

(continued)

Trucking Operations

For facilities ≥ 10 mol/kmol (1% H_2S):

Off-site inspection/monitor results	Odour complaint/facility history	Action
Inspector/air monitor validates odours off lease.		• Licensee where product originated may be requested to suspend facility. • Licensee must suspend trucking operations until product can be transported without releasing any H_2S. • Licensee will be placed on EUB's Enforcement Ladder as a major noncompliance.

For facilities < 10 mol/kmol (1% H_2S):

Off-site inspection/monitor results	Odour complaint/facility history	Action
Inspector/air monitor validates odours off lease.	• Initial (first) complaint.	• Licensee must suspend trucking operations until product can be transported without releasing any H_2S. • Failure to comply will result in suspension of facility and licensee will be placed on EUB's enforcement ladder as a major noncompliance.
Inspector/air monitor validates odours off lease.	• Documented complaint history on facility/trucking operation. • Previous odour mitigation requested by EUB.	• Licensee may suspend facility. • Licensee must suspend trucking operations until product can be transported without releasing any H_2S. • Licensee will be placed on EUB's Enforcement Ladder as a major noncompliance.

Appendix 13

Field Inspection Branch ERP Review Form

EUB Alberta Energy and Utilities Board

Field Inspection Branch ERP Review

Licensee ____________________ Facility Type ____________________ Facility Name ____________________
Date ____________________ Field Centre ____________________ Inspector ____________________

Mandatory

The following six requirements must be met to achieve a satisfactory inspection regarding emergency response planning:

		Yes	No	N/A
1.	Is there a site-specific emergency response plan (ERP) where required?			
2.	Is safety equipment specified in the ERP installed?			
3.	Is a copy of the ERP readily available on site?			
4.	Is the ERP updated yearly, with yearly exercises held and details documented?			
5.	Is licensee/operator on-site representative familiar with the ERP?			
6.	Does licensee/operator communicate regularly with residents in the emergency response zone (EPZ)?			

Supporting Information

The following seven criteria must be reviewed with the licensee's representative to gauge operator awareness and ERP competencies. These criteria will assist the inspector in determining the rating for the above requirements. Criteria 7: Resident Contact must be confirmed by a minimum of two resident contacts per ERP. The resident contact form must also be completed.

1. Location and reporting
2. Responsibilities of company personnel
3. Monitoring and isolating the hazard area
4. Evacuation procedures
5. Ignition guidelines
6. Communication
7. Resident contact

1.	**Location and Reporting— Does the ERP**	**Yes**	**No**	**N/A**
a)	identify facilities covered by the plan?			
b)	provide legal descriptions and maps detailing EPZs and resident locations (including trappers and places of business)?			
c)	include a comprehensive list of all wells, pipelines, and production facilities, including maximum potential release rates or volumes and the corresponding planning zones?			
d)	describe how incidents are reported to EUB and outside agencies?			
e)	describe levels of alert so that they are clearly understood?			

2.	**Responsibilities of Company Personnel— Does the ERP**	**Yes**	**No**	**N/A**
a)	identify personnel responsible for initiating emergency procedures?			
b)	outline responsibilities of key individuals?			
c)	identify names and telephone numbers of key individuals (especially in the emergency phone list)?			
d)	identify alternate/backup personnel?			

3.	**Monitoring and Isolating the Hazard Area—Does the ERP**	**Yes**	**No**	**N/A**
a)	describe monitoring devices and circumstances for handheld monitors (draeger units/personal monitors)?			
b)	identify sources of mobile and stationary air monitoring units?			
c)	describe procedures for blocking access routes by licensee and others (isolating hazard)?			

4.	**Evacuation Procedures—Does the ERP**	**Yes**	**No**	**N/A**
a)	outline methods and procedures for public evacuation and sheltering?			
b)	include statement of information to be given to residents within the EPZ that describes location and nature of hazard?			
c)	describe evacuation route(s)?			
d)	identify the location and phone number of the evacuation centre?			
e)	describe procedures for locating and ensuring the safety of transients and other industrial operators?			
f)	list trapper and transient phone number(s) and address(es)?			
g)	describe methods of transient surveys (hunters, etc.)?			
h)	describe procedures for notification and evacuation of schools?			
i)	describe procedures for calling down emergency status and resuming operations?			

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(continued)

5. Ignition Guidelines—Does the ERP	**Yes**	**No**	**N/A**
a) identify personnel with authority to ignite release?	___	___	___
b) list criteria to be considered for ignition?	___	___	___

6. Communication— Does the ERP describe procedures for	**Yes**	**No**	**N/A**
a) establishing an on-site command post (OSCP)?	___	___	___
b) establishing an off-site emergency operations centre (Off-Site EOC)?	___	___	___
c) licensee to inform and update the public of the hazard?	___	___	___
d) communicating with the public and media through press releases?	___	___	___

7. Resident Contact—Has the licensee ensured that	**Yes**	**No**	**N/A**
a) resident contact has been made and/or maintained?	___	___	___
b) an information package has been given to residents?	___	___	___
c) the information package describes characteristics and hazards of H_2S and SO_2?	___	___	___
d) the information package describes key actions/responses in an emergency?	___	___	___
e) the information package provides 24-hour company telephone number(s)?	___	___	___

Based on the above criteria, rate the licensee's enforcement for compliance/noncompliance status as detailed in *Guide 36*, *Guide 37*, *Guide 64*, and *Guide 66*. Document the results on the appropriate Production/Pipeline/Drilling/Servicing Inspection form using the criteria listed below. Attach this review to the licensee's file in the appropriate Field Centre.

Legend: **X - Satisfactory** **U - Minor** **M - Major** **S - Serious**

S No approved site-specific ERP where required.

S Safety equipment specified in ERP not installed.

M Copy of ERP not readily available.

M ERP manual not updated yearly, and exercises not held or details not documented.

M Operator on-site representative not familiar with ERP.

U Operator not communicating with residents in EPZ.

Appendix 14 Records Review of Operator Compliance

In preparation for any planned field inspection, each inspector should become familiar with the facilities to be visited.

The first item to check is the Production Surveillance System (PSS). A review of the information in PSS will tell you when the facility was last inspected, any deficiencies found, and the compliance history of the operator.

As part of any planned facility inspection, each inspector should review the "S" statements associated with the facility to get a snapshot of what can be expected. While Field Centres are not responsible for an in-depth review of the "S" statements, inspectors should also verify the conditions that exist in the field and ensure that the "S" statements reflect such conditions.

For oil batteries, gas batteries, water injection systems, and gas injection systems, the "S" statements can be obtained on line from the Production Injection Disposition (PID) system, which is accessed through the mainframe by opening the DC2 session, then entering "**51**" to access "Query – PID General." To review S-8, S-20, or S-21 statements, contact Production and Well Data Services in Calgary. They will send out the copies of the forms requested. For S-24 and S-25 statements, contact the Operations Group, Waste Operations Section. For S-30 statements, contact the Operations Group, Production Operations Section.

Records Review

Check the Corporate Compliance database, accessed through mainframe by opening DC2, to establish if the company is in good standing. If it is on "Refer" status, contact the Corporate Compliance Group to determine how this may impact the planned inspection.

On the PID system, review the control data for the battery to be inspected. Check to ensure the location is accurate, the Field Centre is correctly assigned, the facility type is correct, and the battery has an approval number. If any of these items is not correct, it can be updated at the Field Centre level. At least one person in each Field Centre has the appropriate authority for updating the system. If the operator of the facility is not correctly identified, contact Corporate Compliance to determine if the facilities have been transferred.

The "S" statement review procedures should be as follows:

S-1 Statement

- Ensure that S-1 statements are being submitted.
- Ensure that the accounting method is compatible with the well measurement (measured production, prorated production, and effluent measurement, etc.).
- Ensure that water measurement and accounting for gas wells are in accordance with *Guide 4.*
- Confirm that gas production is properly reported in accordance with the approval and/or equipment at the well site (measured or approved GOR factor).
- Confirm that water production is properly reported. If water production is reported, ensure that measurement and sampling procedures conform to regulations.
- Confirm that oil production is properly reported based on method of production (condensate at gas wells, heavy oil).
- Review proration factors to determine if they are within acceptable standards as outlined in *ID 94-1* (Attachment 2).
- Check that production is reported for all wells.

S-2 Statement

- Review flare volumes.
- Ensure the fuel gas is reported.
- For an oil battery ensure that vented gas is reported if there is no vapour recovery or if the vapour recovery unit is not able to collect all stock tank vapours.
- Confirm the source of questionable entries. Do the movements in and out of the facility seem reasonable?
- Ensure that inventories for liquid hydrocarbons and water are not exceeding storage capacity.
- Ensure that the metering difference is reasonable for those facilities required to report a metering difference on the S-2 statement (±5 per cent). Proration batteries should not report metering differences.
- Does facility receive trucked production that may require special metering/tank gauging?

S-8 Statement

- Ensure that a metering difference is reported on measured gas systems where applicable and that a metering difference is not reported on effluent measurement systems. The difference should not exceed ±5 per cent.
- Ensure that fuel and flared gas volumes are reported. Confirm if fuel gas is obtained from another source.
- Ensure that flare volumes are acceptable.
- Ensure that processing shrinkage is reported if liquid hydrocarbons are disposed of from the gas gathering system.

S-18 Statement

- Watch for excessive volumes of skim oil ("excessive" meaning > 1 per cent skim oil for three consecutive months at water disposal/injection systems).
- Is source water measured?
- Ensure that the metering difference is reasonable (± 10 per cent).

S-20 Statement

- Review inlet volumes and ensure that products conform to the plant process and approval.
- Ensure that flare gas volumes are reported properly. If reporting zero flare, is that reasonable?
- Ensure that the metering difference is acceptable (±5 per cent). Compare the metering difference on the S-20 with those reported on the S-8 statements feeding the plant; these may offset each other, indicating a problem with inlet measurement. Review the metering difference for trends and anomalies.
- Ensure that flare volumes are acceptable.

S-21 Statement

- Confirm the source of entries (inventories, other receipts, dispositions, and details of shipments).
- Ensure that other receipts and shipments are properly coded and identified.
- Ensure that the liquids reported are indicative of the plant process and approval (e.g., fractionation plants report C3, C4, C5 separately, LPG plants report LPG/NGL mix, and condensate recovery plants report pentanes plus).

Procedure to retrieve inspection information by operator (provincially) for oil and gas facilities

Go to "DC2"
Go to "75" Production Surveillance
Go to "90" Request Reports Menu
Go to "50" Inspections Recorded

From the screen:

Area Office Code = delete office code number
Operator Code = enter operator code number
Field Code = leave blank
Location Code = leave blank
NW/SE Corners = leave blank
H_2S Category = leave blank
Battery Config = leave blank
Bty/Fac Type = enter 1 for oil
= enter 2 for gas
Operation at Time of Inspection = leave blank
Contact Name = leave blank
Inspection Result = enter "M" for major,
= enter "U" for minor,
= enter "X" for satisfactory
Inspection Type = leave blank
Approval # = leave blank
Date From/To = enter dates
Follow-up Date = leave blank
Delivery to Facility = leave blank
Inspector ID = leave blank
Press "ENTER"
Select "30" = location/battery/satellite
Press "ENTER"

This batch report will print all inspection results for the operator for the time period entered. Refer to Field Surveillance Enforcement Ladder (Appendix 2) to determine the follow-up required.

Appendix 15 References and Contacts Cited

EUB Documents*

Internal Guide 8: Safety Manual
Guide 4: Determining Water Production at Gas Wells
Guide 7: Production Accounting Handbook
Guide 34: Guidelines for Automated Measurement System Applications
Guide 38: Noise Control Directive User Guide
Guide 46: Production Audit Handbook
Guide 55: Storage Requirements for the Upstream Petroleum Industry
Guide 56: Energy Development Application Guide and Schedules
Guide 58: Oilfield Waste Management Requirements for the Upstream Petroleum Industry
Guide 59: Well Drilling and Completion Data Filing Requirements
Guide 60: Upstream Petroleum Industry Flaring Guide

ID 90-2: Gas Meter Calibration
ID 90-4: Suspension Guidelines for Inactive Wells
ID 91-2: Corporate-Level Emergency Response Plans
ID 91-3: Heavy Oil/Oil Sands Operations
ID 94-1: Measurement of Oil, Gas & Water Production
ID 95-3: Storage Requirements for the Upstream Petroleum Industry
ID 96-2: Facility Application Requirements
ID 96-3: Oilfield Waste Management Requirements for the Upstream Petroleum Industry
ID 98-2: Minimum Wellhead Requirements
ID 99-3: Surface Casing Vent Flow/Gas Migration (SCVF/GM) Testing and Requirements
ID 99-6: Upstream Petroleum Industry Flaring Requirements
ID 99-8: Noise Control Directive
ID 2001-5: Site-Specific Emergency Response Plans for Sour Operations, Emergency Planning Zones, and Reduced Planning Zones

IL 87-1: Compressibility Factors Used in Gas Volume Calculations and Physical Property Data for Natural Gases
IL 88-5: Application for Approval of Natural-Gas-Driven Compressors (Amended by ID 96-2)
IL 90-6: Measurement Guidelines – Trucked Oil Production
IL 90-17: Emergency Procedure Plans for Sour Gas Facilities
IL 91-3: Well Production Records and S-4 Submissions
IL 91-9: Exemption from Gas Measurement Crude Oil/Bitumen Wells
IL 92-8: Crude Oil Pipeline Truck Terminal Measurement Guidelines
IL 93-10: Revised Measurement and Accounting Procedures for Southeastern Alberta Shallow Gas Wells
IL 94-18: Isolation Packer Tests—Testing and Reporting Requirements
IL 96-4: EUB Policy Update and Clarification on the Use of Earthen Pits
IL 98-2: Suspension, Abandonment, Decontamination and Surface Land Reclamation of Upstream Oil and Gas Facilities
IL 99-4: EUB Enforcement Process, Generic Enforcement Ladder, and Field Surveillance Enforcement Ladder
IL 99-5: The Elimination of the Surface Release of Produced Water

IMP-07: Shop Calibration of Liquid Meters

Other Documents

American Gas Association Report No. 3, Orifice Metering of Natural Gas
American Gas Association Report No. 7, Measurement of Gas by Turbine Meters
American Gas Association Report No. 8, Compressibility and Super-Compressibility for Natural Gas and Other Hydrocarbon Gases
American Petroleum Institute Manual of Petroleum Measurement Standards (API-MPMS)
Environmental Protection and Enhancement Act, Substance Release Regulation (AR 124/93)
Industry Recommended Practices for Heavy Oil and Oil Sands Operations – ARP 3.3 and 3.4
Miller, R. W., 1983, Flow Measurement Engineering Handbook (New York: McGraw-Hill)
National Standard of Canada CAN/CGA B149.2: Propane Installation Code
Oil and Gas Conservation (OGC) Regulations
Orifice Meter Constants Handbook E-2

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* EUB documents are available on the EUB Web site <www.eub.gov.ab.ca> or from EUB Information Services, 640–5 Avenue SW, Main Floor, Calgary AB T2P 3G4; Tel: (403) 297-8190; Fax: (403) 297-7040.

Contacts

EUB Facilities Applications Group: (403) 297-4369
EUB Production and Well Data Services : (403) 297-8952
EUB Surveillance Branch,
  Corporate Compliance: (403) 297-4485
  Fraud Investigations Coordinator: (403) 297-6952
  Production Operations: (403) 297-6952
  Waste Operations: (403) 297-6952
EUB Field Centres
  Bonnyville: (780) 826-5352
  Midnapore: (403) 297-8303
  Drayton Valley: (780) 542-5182
  Grande Prairie: (780) 538-5138
  Medicine Hat: (403) 527-3385
  Red Deer: (403) 340-5454
  St. Albert: (780) 460-3800
  Wainwright: (780) 842-7570
EUB Field Sub-offices
  Fort McMurray: (780) 743-7214
  High Level: (780) 926-5399
Alberta Environment, Pollution Control Division: 1-800-222-6514
Alberta Human Resources and Employment, Workplace Health and Safety(formerly OH&S): (780) 427-8848
Alberta Municipal Affairs, Safety Services (formerly Electrical Protection): (780) 427-6868